REVIEW OF ELECTRICITY TRADING ARRANGEMENTS

BACKGROUND PAPER 2

ELECTRICITY TRADING ARRANGEMENTS IN OTHER COUNTRIES

FEBRUARY 1998

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CONTENTS

1. INTRODUCTION

1.1 On 23 October 1997[1], the Minister for Science, Energy and Industry announced that he had asked the Director General of Electricity Supply ('the DGES') to consider how a review of electricity trading arrangements ('the Review') might be undertaken. On 5 November 1997[2], OFFER issued a consultation paper setting out initial views on the objectives, scope and process of the Review and inviting the views of others. These views were taken into account in drawing up advice to the Minister and proposed Terms of Reference for the Review. The Minister agreed the proposed Terms of Reference and, on 28 January 1998, OFFER published the advice on the Terms of Reference[3] which the DGES had presented to the Minister.

Process and Timetable

1.2 The Minister has indicated that he wishes to receive a report by early July 1998, in order to consider what, if any, changes in legislation are required, consistent with the timetable for possible legislation following the government's review of utility regulation.

1.3 To achieve openness and transparency the Review process will include the publication of background, working and consultation papers, explanatory workshops to ensure interested parties are familiar with key issues, public seminars to examine and debate options for change and interim conclusions, and the placing of all third party contributions in the public domain.

Organisation of the International Background Paper

1.4 This background paper describes the electricity trading arrangements in a range of countries. (A initial background paper, which is being published at the same time, covers electricity trading arrangements in England and Wales.)

1.5 Chapter 2 provides background information on the electricity market in each of the countries being considered, including the structure of the industry and the timetable for liberalisation. Chapter 3 describes the regulatory background and governance arrangements in each market. Chapters 4 and 5 respectively discuss trading inside and outside the pool, while Chapter 6 covers financial contracts and trading. Chapter 7 outlines the development of competition in generation and supply in each market, and Chapter 8 focuses on transparency and related issues. Chapter 9 concludes the document with a summary of the trading arrangements in other countries and draws out comparisons to the England and Wales market.

[1] Minister's speech to Pool AGM, 23 October 1997
[2] Review of Electricity Trading Arrangements – A Consultation Paper, OFFER, November 1997
[3] Review of Electricity Trading Arrangements: Advice on Terms of Reference, OFFER, January 1998

Next Steps

1.6 A first explanatory workshop to discuss this background paper and the background paper on trading arrangements in England and Wales was announced by Press Release on 5 February. The press release invited nominations to attend the workshop on 23 February at the National Exhibition Centre.

1.7 The timetable for publishing subsequent papers and holding additional workshops and seminars is set out in Appendix 1.

Consultation

1.8 If you wish to make comments or submissions relating to this background paper, it would be helpful to receive them by 6 March 1998. Responses should be addressed to:

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1.9 Responses will be place in OFFER's library.

Acknowledgements

In the course of researching and writing this paper, we have drawn upon materials from many government organisations, market participants, academics and analysts. Including:

Australian Competition & Consumer Commission (ACCC)
California Energy Commission
California Public Utilities Commission (CPUC)
CAMMESA
Department of Energy, US
ECNZ, New Zealand
El-Ex
EMCO, New Zealand
Energy and Power Risk Management
Energy-on-line
Federal Energy Regulatory Commission (FERC)
Ministry of Commerce, New Zealand
National Electricity Market Management Company (NEMMCO)
Nord Pool
Nordel
Norwegian Electricity Federation (SOL)
Norwegian government information service (ODIN)
Norwegian Water Resources and Energy Administration (NVE)
NUTEK
Office of the Regulator General, Victoria (ORG)
Pontifica Universidad Catolica de Chile
Power Economics
Public Utilities Fortnightly
St. Clements/ILEX: Electricity Markets, Principles & Practice
Sydney Futures Exchange
The Australian National Electricity market Exchange (NEMEX)
The Electricity Supply Association of Australia
TransGrid, NSW
Victoria Department of Treasury and Finance
Victoria Power Exchange (VPX)
Western Systems Co-ordinating Council (WSCC)

2. OVERVIEW

2.1 This background paper is intended to provide an introduction to the electricity trading arrangements within a number of countries in which liberalisation of the power sector has either already taken place or is currently underway. The aim is to illustrate how electricity markets in different countries have applied alternative solutions to a broadly common set of issues and problems.

2.2 At the time of the Pool's establishment in 1990, the England and Wales electricity industry was one of the first in the world to introduce competition into the generation and supply sectors. Indeed, all of the electricity sectors discussed in this paper began liberalising their trading regimes after the deregulation in England and Wales. The England and Wales model has thus been observed closely by industry players seeking to develop competitive trading arrangements in several electricity sectors around the world. The electricity markets described in this paper have features in common with the England and Wales system and with each other, but key differences in the details of the trading arrangements can be found in each case.

2.3 Nevertheless, these competitive wholesale trading arrangements all share the same need to match supply and demand. Since power cannot be stored economically in significant quantities, this matching process must be carried out instantaneously. This requires some degree of central co-ordination whether the electricity industry consists of a single vertically integrated public sector utility or a multitude of competing generators and suppliers.

2.4 Issues such as security of supply, demand uncertainty, plant failure and transmission losses need to be addressed by all wholesale electricity markets. To some extent, the physical characteristics of the electrical system may dictate the most appropriate choice of trading arrangements in a particular country. For example, network transmission constraints will be more significant in some countries than others.

2.5 The electricity systems described in this paper represent a broad spectrum of the types of competitive trading arrangements developed over the last decade. The markets considered are:

- Scandinavia (Nord Pool),
- Australia (Victoria and NEM),
- New Zealand,
- South America (Argentina),
- USA (California).

Scandinavia (Nord Pool)

2.6 Table 1 summarises the key statistics for the Norwegian and Swedish electricity systems.

Table 1 Key Statistics For Scandinavia

	Norway	Sweden
Peak demand (GW)	17.7	23.0
Annual generation (TWh)	105	136
Capacity (GW)	27.6	34.2
Output mix	99% hydro	37% hydro, 50% nuclear, remainder thermal

Source: Nordel Annual Report 1996

2.7 The state-owned generator, Statkraft, accounts for around 30% of Norwegian power production. Private sector industrial companies, such as Norsk Hydro, produce around 20% of generation, with most of the remainder being supplied by some thirty municipally owned utilities. The majority of capacity in Sweden is owned by three companies, Vattenfall (50%), Sydkraft (15%) and Stockholm Energi (6%). Before restructuring, Norway and Sweden each had over 200 local distribution companies, mostly municipal utilities. There has been some amalgamation of distribution companies in Sweden over recent years.

2.8 Norway implemented electricity sector reforms in 1991 with the removal of supply franchises and the granting of third party access to transmission and distribution networks. Sweden introduced similar measures in 1996. Finland introduced supply competition for large consumers (those with a maximum demand over 500 kW) in 1996 and extended choice to all customers in 1997.

2.9 A generator-only power pool was established in Norway in 1971. This was essentially only used for balancing purposes with the majority of power being traded under bilateral contracts. Pool membership was extended to non-generators in 1991 and in January 1996, a joint power exchange, Nord Pool[4], covering Norway and Sweden began operation. Finland launched an electronic power exchange, El-Ex, in August 1996. Finnish players are also free to trade on Nord Pool. The El-Ex and Nord Pool power exchanges are expected to merge in the future.

Australia

2.10 Electricity restructuring in Australia has followed different paths in each state, but a national electricity market (NEM) covering the south-eastern states is due to commence in May 1998.

2.11 Victoria was the first state to introduce competitive wholesale trading arrangements. Reform of Victoria's electricity sector commenced in 1993 with the break up of the vertically integrated state utility into generation business units, five regionally based

[4] The company that became Nord Pool was initially established in 1993 as a subsidiary of the Norwegian transmission company, Statnett, operating the Norwegian pool.

distributors and a transmission company. A power exchange was established at the same time. The generation sector is now highly atomistic, with the majority of the seven main generators operating one station each. Between 1995 and 1997, the five distributors and the four brown coal-fired stations were all transferred to the private sector in trade sales. Supply competition is being introduced in phases, with the initial market threshold being set at 5 MW, and full competition scheduled for 2001. Currently all customers with annual demands over 750 MWh can choose their supplier and this limit is due to fall to 160 MWh in July 1998.

2.12 In New South Wales, Pacific Power, the state-owned generation and transmission utility, has been split into three portfolio generators and a transmission company. Six state-owned distributors were formed from 25 local distribution authorities in 1995. Since July 1996, customers who consume over 750 MWh per year have been able to choose their supplier. Table 2 summarises the key statistics for the electricity systems of Victoria and New South Wales.

Table 2 Key Statistics For Victoria And New South Wales

	Victoria	**New South Wales**
Peak demand (GW)	7.1	10.4
Annual generation (TWh)	37.1	54.1
Capacity (GW)	8.4	14.8
Plant mix	70% brown coal, 20% hydro, 10% gas	79% black coal, 19% hydro, 2% gas

Note: Capacity includes each state's entitlement to the 3.7 GW Snowy Mountains hydro scheme.

2.13 Victoria's wholesale market, VicPool, began operating in October 1994 and evolved through a number of phases in preparation for the national market. New South Wales launched a wholesale market in May 1996. The preliminary stage of the national electricity market (NEM1) commenced in May 1997 with the implementation of an interface between the power exchanges in Victoria and New South Wales[5]. Under NEM1, South Australia is a participant in VicPool.

2.14 The full national market, NEM, may also involve Queensland and, at a later date, Tasmania. These states are not currently interconnected with the other states but Queensland may be included in the market with a transmission line capacity of zero. The national market systems are currently undergoing trials in Queensland.

[5] For the purposes of this report, we have included the Australian Capital Territory within the New South Wales market.

New Zealand

2.15 Table 3 summarises the key statistics for the electricity system in New Zealand.

Table 3 Key Statistics For New Zealand

Peak demand (GW)	6.2
Annual generation (TWh)	31
Capacity (GW)	7.1
Output mix	66%-83% hydro, 7% geothermal, remainder thermal

2.16 Transmission activities were split out from the state generating utility, ECNZ, in 1993 into a separate grid company, Trans Power. The retail sector was fully deregulated around the same time, with some 50 local distributors losing their monopoly franchises. In 1996, a second state-owned generator, Contact Energy, was established following the transfer of around 22% of ECNZ's generation assets. A competitive wholesale market commenced full operation in October 1996. There are plans to break up ECNZ further.

Argentina

Table 4 Key Statistics For Argentina (SADI)

Peak demand (GW)	12
Annual generation (TWh)	65
Capacity (GW)	20
Output mix	45% thermal, 44% hydro, 11% nuclear

2.17 Electricity reform in Argentina commenced in 1992 with the splitting up of the state-owned generation and transmission companies and the establishment of a framework for wholesale power trading. There are two independent markets. The larger one, SADI, covers the northern and central regions of Argentina while the smaller one, SP, covers the south of the country. SADI and SP are not interconnected. Table 4 summarises the key statistics for the SADI system.

2.18 The high voltage national transmission company and four of the five regional transmission companies have subsequently been privatised. There are now around 40 generating companies, the majority of which are now in the private sector. The regional distributors are currently being privatised. Large customers can buy directly from generators. The competitive threshold has been lowered from 2 MW in 1992 to 100 kW at present.

USA (California)

2.19 As in Australia, electricity restructuring in the United States is essentially taking place state by state. To date, some of the most significant reforms have occurred in California. Details of the Californian electricity system are shown in Table 5.

Table 5 Key Statistics For California

Peak demand (GW)	49.3
Annual generation (TWh)	208
Capacity (GW)	51.5
Output mix	38% gas, 25% hydro, 17% nuclear, 11% renewable, 9% coal

2.20 Three large vertically integrated private sector utilities currently account for the majority of California's generation and retailing, although there are also a number of independent power plants and municipal utilities. The two largest utilities have agreed to divest at least 50% of their generating assets. Deregulation of the wholesale and retail markets had been due to take place simultaneously on January 1 1998, but IT delays have postponed the start date for competition until the spring. All consumers will be given the right to choose their supplier, and a power pool will be established.

3. REGULATORY BACKGROUND AND GOVERNANCE

3.1 This chapter focuses on the types of regulatory framework under which competitive wholesale markets operate. We examine how different trading arrangements have incorporated the two key roles of system operator and market operator, and discuss the procedures each market has adopted for developing the trading arrangements over time.

3.2 A system operator is responsible for ensuring the technical security of the electrical network by co-ordinating the actions of the market players connected to it. For example, a system operator will need to check that the proposed running schedule of generating plant does not violate any technical limits such as transmission constraints. In real time, a system operator's key task is to match supply with demand in response to unforeseen changes in demand or plant availability. Typically, a system operator will also arrange for the collection of the generation and 'offtake' data required for settlement purposes.

3.3 A market operator's primary role is to determine a market clearing price for each trading period by providing a forum for market players to submit bids and offers.

3.4 In some countries, the roles of market and system operator are carried out by the same organisation while in others they are undertaken independently. In some market structures the system operator is also the owner of the transmission network but others have sought to distinguish the control and ownership of these assets.

Scandinavia

3.5 The primary duty of the Norwegian regulator, NVE, is to supervise the monopoly activities of transmission and distribution. NVE also has a duty to promote competition in generation and supply, and can intervene to prevent abuses of market power. In Sweden, NUTEK performed a similar regulatory role but in 1998 a new Energy Authority was established to take its place.

3.6 System operation in Norway and Sweden is undertaken by the respective owners of the national transmission networks, Statnett and Svenska Kraftnät. Both these companies were created through the removal of transmission assets from state-owned generating utilities, Statkraft in Norway and Vattenfall in Sweden.

3.7 The wholesale market operator, Nord Pool, is jointly owned (50:50) by the Norwegian and Swedish grid companies. Plans have recently been announced for the Finnish national grid operator to take a stake in Nord Pool in return for shares in the Finnish power exchange, El-Ex. Pool trading is not mandatory and most electricity is traded outside the pool through bilateral contracts between market participants. Any company wishing to trade in Nord Pool must first become a member. Membership is open to generators, distributors, suppliers, industrial customers, traders and brokers. The number of members has grown steadily in recent years, reaching 199 in January 1998. Although the great majority of members

are Norwegian or Swedish, there are also participants from Finland, Denmark and the UK.

3.8 Development of the Nord Pool is decided by Nord Pool's own board of directors. An unweighted majority voting system is adopted in considering changes to the trading rules. Pool members do not have voting rights, though they can influence decisions through a market advisory board, the president of which also sits on the main Nord Pool board. The advisory board in turn receives recommendations from two product development sub-groups, each comprising 10 actively trading members. The advisory board and sub-groups are elected by pool members. Some companies have argued that members should have an ownership stake in Nord Pool but both the Norwegian and Swedish governments have expressed their preference for an independently-owned trading body. There is no direct consumer representation in Nord Pool.

Australia

3.9 In Victoria, the Office of the Regulator General (ORG) is charged with promoting competitive behaviour and protecting consumer interests across a range of industries previously in the state sector, including electricity. All participants in the electricity market are required to hold appropriate licences issued by the ORG. One condition of the licences is compliance with the pool rules and system code. Changes to the market rules must be approved by the ORG.

3.10 The Victoria Power Exchange (VPX) was established as a state-owned body to act as both market and system operator. VPX will continue to run the VicPool wholesale market until the start of the national market in May 1998. Participation in VicPool is compulsory for all generators with more than 30 MW of capacity and all suppliers. VPX is also responsible for transmission system planning, and may organise tendering for network extensions. Grid ownership and control have been separated, PowerNet Victoria being the owner and maintainer of the transmission network.

3.11 The development of the Victorian market is primarily in the hands of two bodies, the VPX board and the Pool Consultative Committee (PCC). The VPX board comprises nine directors - four non-industry representatives (including the VPX Chairman), two generator representatives, two distribution/supplier representatives and one transmission business representative. In addition, a member of the Government (Energy Project Division) sits on the board as an observer. The VPX board is responsible for market strategy and policy direction. It can also act as a tiebreaker if the PCC is unable to reach a decision. All VPX board members have equal voting rights and a simple majority is sufficient to carry a vote. VPX also runs a dispute resolution panel composed of industry representatives and an independent chairperson.

3.12 The PCC was established by VPX and is more industry focused than the VPX board. It can set policy, but primarily deals with issues on a detailed implementation level. The PCC comprises eleven members - three VPX representatives, three generator representatives, one distribution/supplier representative, three retailer representatives

and one transmission business representative. There are no consumer representatives on the PCC, but issues can be referred to the ORG which runs a customer consultative committee.

3.13 The regulatory framework allows for delegation of pool rule approval to the PCC but this has yet to be put in place. If authority is delegated, rule changes will require the approval of 8 out of the 11 members, while a vote of 6 or more would amount to a recommendation to the ORG. Currently the ORG has to approve all pool rule changes after considering the voting margins and the differing views expressed within the PCC. ORG has the power unilaterally to make Pool Rule changes.

3.14 The Australian National Electricity Market (NEM) is due to commence full operation in May 1998. An interim version, NEM1, involving Victoria and New South Wales has been operating since May 1997. Participation in the NEM will be mandatory.

3.15 The basis of the NEM trading arrangements flows from co-operative legislation in each state, which provides for a compulsory code of conduct. Two main bodies have been established. The National Electricity Market Management Company (NEMMCO) will act as the market and system operator, whilst the National Electricity Code Administrator (NECA) will be responsible for code compliance and enforcement.

3.16 NEMMCO is a non-profit making organisation whose board members are appointed by the participating states. NEMMCO will co-ordinates the overall operation of the system and be responsible for interstate transmission planning, with regional planning continuing to be performed by the relevant body in each state.

3.17 NECA is a non-profit making organisation whose board members are also appointed by the participating states. At present, the board includes three directors from outside the electricity industry. NECA was created to administer and enforce the National Market Code. It will monitor the wholesale market and consult participants on changes to the trading arrangements.

3.18 The wholesale electricity market is also subject to federal regulation by the Australian Consumer and Competition Commission (ACCC), within the existing competition law framework. The ACCC is the main competition authority in Australia. Its function in regard to the NEM is to approve code changes identified by NECA and to investigate any anti-competitive behaviour, taking action where necessary. Once identified, anti-competitive behaviour will be dealt with by the ACCC in accordance with the relevant Trade Practices Act provisions.

3.19 With the start of the NEM in May 1998, NEMMCO and NECA will take over most of the functions of VPX and all the functions of the PCC within Victoria. VPX's regional role in transmission system planning will be subsumed into VEN Corp, a new state-owned body which will also be responsible for operating Victoria's gas network. Although NECA and the ACCC will oversee the wholesale markets, the

distribution and retail sectors will remain subject to regulation by the appropriate authorities in each state. The ORG will thus have a continuing role in Victoria.

New Zealand

3.20 There is no industry specific regulator in New Zealand, instead the electricity industry is covered by general competition legislation. Consequently, there are no licensing requirements for new entrants.

3.21 Industry participants can opt to trade through the New Zealand Electricity Market pool (NZEM) or bilaterally. Electricity Market Company (EMCO) is the operator of NZEM. EMCO is a commercial company currently owned by three industry participants, although this is under review. The grid owner, Trans Power, acts as the system operator and is responsible for system security. NZEM's rules identify specific market roles such as scheduler, despatcher, pricing manager, clearing manager, reconciliation manager and settlement manager. Fixed term contracts for the provision of these services are awarded by competitive tender. All the initial contracts were won by EMCO and Trans Power.

3.22 The NZEM is largely self regulating, although there is some participation by non-industry appointees. The NZEM rules contain a number of 'Guiding Principles'. These include fostering efficient and competitive markets and facilitating new entry. The voting rules require a majority from both generators and purchasers to enable market rule changes to be implemented. The allocation of votes within each side of the industry is on the basis of volumes traded, with a cap of 45% on any participant. Rule changes can only be adopted through a vote of market participants. Possible rule changes are first investigated by a working group of industry participants, the conclusions of which are submitted to the Rules Committee who then make their own recommendations. The issue is then put to a vote by market participants.

3.23 NZEM rule administration, general market monitoring and dispute resolution is achieved through the Market Surveillance Committee. The members of this committee are appointed by the various classes of market participants but must be independent of the industry.

Argentina

3.24 Overall control of the Argentine electricity industry is vested in the Secretary of Energy, who has the power to set policy, define market rules and award concessions for hydro and nuclear generation and transmission projects.

3.25 An independent regulatory body, the National Electricity Regulatory Board (ENRE) operates under the supervision of the Secretary of Energy. ENRE's main functions are to adjudicate on disputes between industry participants and to ensure that members of the wholesale markets comply with the relevant laws, regulations and concessions granted by the Secretary of Energy.

3.26 Participants have the option of trading through the voluntary Wholesale Electricity Market (WEM) or bilaterally with each other (but bilateral contacts do not imply despatch priority). WEM is run by Compania Administrado del Mercado Mayorista Electico Sociedad Anonima (CAMMESA), a private non-profit making company. The Secretary of Energy and sector associations of transmission companies, generators, distributors and large customers each have a 20% share.

3.27 CAMMESA carries out the main functions of the market including scheduling and despatch, price setting, settlement and setting reserve levels. CAMMESA is responsible for guaranteeing the transparency and equity of the decisions taken in the WEM. Six transmission companies own and maintain the network, but there are competitive arrangements for grid extensions. Potential beneficiaries of a new transmission line can petition the regulator ENRE to authorise a public tender for the project.

3.28 Each sector association elects two representatives to the CAMMESA board every two years. The CAMMESA board is responsible for the day to day operation of the market and for identifying and recommending structural changes to the Secretary of State. If accepted, the Secretary of Energy will pass a resolution effecting the change.

California

3.29 In California, the Federal Energy Regulatory Commission (FERC) has jurisdiction over transmission and inter-state issues. The California Public Utilities Commission (CPUC) regulates the other elements of the industry. Regulation of generation and supply will be phased out as competition develops but regulation of transmission and distribution will continue.

3.30 The restructuring process has led to the creation of an Independent System Operator (ISO) and a wholesale power exchange (PX). Both the PX and ISO are separately incorporated public benefit, non-profit corporations. The PX will have no financial interest in generation and no ownership ties to the ISO. Market participants will have the option to trade through the PX or bilaterally with each other. However, the three large vertically integrated private utilities must trade through the PX until the year 2002.

3.31 The ISO will operate the transmission network as an integrated system but the three large utilities will continue to own and maintain the assets. Participants who opt to trade bilaterally rather than through the PX will need to interact with the ISO through a scheduling co-ordinator. Although the market and system operator functions are to be carried out by separate organisations, there is clearly a need for active co-ordination between them. Incompatibility between the PX and ISO computer systems was the chief cause of the market's delayed implementation.

3.32 Both the PX and the ISO have compliance units and market monitoring committees. These will investigate the performance of the market and market power issues and report to their respective boards and the CPUC.

3.33 Legislation governing California's electricity industry restructuring provides for the establishment of a five person Oversight Board. Board members are appointed by the State Legislature. The Board is responsible for overseeing the operation of the PX and ISO and appoints members to the governing boards of both organisations. Legislation requires that both the ISO and PX governing boards consist of a majority of persons who are unaffiliated with generation, transmission or distribution corporations. Representatives include end users from the industrial, commercial, residential and agricultural sectors, as well as public interest groups and non-market participants. The Oversight Board also serves as an appeal board for majority decisions of the ISO governing board.

4. TRADING INSIDE THE POOL

4.1 As outlined in the previous chapter, electricity restructuring in each of the markets considered in this paper has entailed the creation of a wholesale power exchange or pool. In some markets, such as Norway and New Zealand, trading through the pool is optional while in others participation is mandatory, as in England and Wales. The procedures for trading outside the pool in each country are discussed in the next chapter. Here, we describe the key features of the pool mechanisms themselves.

4.2 All pool trading systems need to match supply and demand. The trading systems described in this paper have followed a number of different approaches in attempting to achieve this goal. For example, the pools differ in terms of how and when prices are set. Key differences include whether generators are explicitly rewarded for availability as well as for providing energy and how to incorporate the demand side within the market process. There is also the question of the allocation of risks and responsibilities between the market/system operator and the pool participants. In this chapter, we examine each issue in turn and explore the approaches adopted in the various markets.

Energy prices

4.3 All the wholesale markets described in this paper set the electricity price for each trading period on the basis of the system marginal price during the period. Alternative approaches such as paying generators their bid price rather than the marginal price have been suggested by some industry observers but these have not been adopted in electricity wholesale markets[6].

4.4 Marginal prices for wholesale electricity may be set in advance (*ex ante*), in real time, or after the event (*ex post*).

4.5 Ex ante market prices are determined typically at the day-ahead stage. The demand for electricity can vary significantly over short periods of time, and it is not possible to project demand or generator availability with absolute certainty. The actual use of generation resources will inevitably differ from any projected schedule as a result of under or over delivery of power (due to plant failures and generator errors), under or over consumption (due to demand forecasting errors) and transmission constraints (to be discussed later in this chapter). Markets with ex ante prices therefore require a balancing mechanism to address any deviations between the actual and projected schedules.

4.6 One option for carrying out this reconciliation process is an uplift arrangement in which the cost of any changes to the ex ante market schedule are recovered through a general charge on market participants, as in the England and Wales Pool. An alternative approach is the creation of one or more secondary balancing markets.

[6] There were trials of a pay as bid pool system in Ontario, Canada, in 1996.

This involves the market or system operator inviting bids and offers from participants willing to increase or decrease generation or consumption from their scheduled levels at short notice. The system operator calls upon these resources in price order to meet any imbalances that arise. Secondary market prices are determined ex post on the basis of the balancing resources actually utilised in each trading period. Deviations from ex ante traded quantities can be cashed out at this price. Transco's flexibility mechanism essentially performs this secondary market function in the UK gas market.

4.7 Since ex post market prices reflect the actual operating state of the system in each trading period, no balancing mechanism is required. Typically, the market operator will publish indicative prices in advance to provide participants with an opportunity to adjust their generation or consumption patterns, but these price forecasts are not used for settlement purposes. The duration of market trading periods is usually half an hour or an hour, and so ex post pricing rules need to define the treatment of schedule variations within a period. An expensive generating plant that is only required for a few minutes to cover a demand spike could set a high marginal price for the period, or receive an averaged system marginal price, possibly with a compensation payment reflecting its bid price.

4.8 Aside from the issue of when prices are set, wholesale markets also differ in terms of the firmness of participants' bids and offers. Some pool systems give participants the opportunity to rebid both prices and volumes as the trading period approaches, while others only permit quantity adjustments for strictly technical reasons. A generator whose actual output is less than that scheduled, perhaps due to plant failure or a commercial decision, would merely forego revenue in some markets but would pay an ex post imbalance charge in others.

Scandinavia (Nord Pool)

4.9 Nord Pool operates a day-ahead spot market (Elspot), a forwards market and a futures market (Eltermin). Futures and forwards trading are discussed in more detail in Chapter 6. Participation in these markets is optional, and significant trading occurs via bilateral contacts.

4.10 Having taken account of any obligations under physical bilateral contracts, spot market participants submit generation offers and demand bids in the form of a price/volume curve for each hour of the following day. Nord Pool sets hourly ex ante prices at the intersection of the aggregate supply and demand curves. By 13:30 on the day-ahead, Nord Pool informs each participant of its generation or purchase commitments in the spot market and allows participants 30 minutes to check that their net trading position is in accordance with their bids and offers. Once confirmed, accepted bid and offer quantities become firm contracts for physical delivery. Participants have no opportunity to revise their bids and/or offers. By 19:00 on the day-ahead, all industry players must inform the relevant system operator of their intended generation or offtake profiles, including both spot market and bilateral contract commitments.

4.11 Until April 1997, Nord Pool also used to operate a within day regulating market for system balancing in Norway. Real time balancing in Norway and Sweden is now undertaken by the respective system operators, Statnett and Svenska Kraftnät. Generators and consumers willing to adjust their scheduled quantities within 15 minutes notice can submit offers and bids until 19:30 on the day-ahead. An ex post balancing market price is set each hour by the marginal bid or offer used. This price is used to settle any imbalances from a participant's day-ahead commitments.

Australia

4.12 Australia's new National Electricity Market (NEM) differs in many aspects from the VicPool market which operated in Victoria between 1994 and 1997. Since VicPool can be regarded as a modified version of the England and Wales Pool, it provides an interesting market model even though it has now ceased operating as an independent entity. We therefore describe VicPool and NEM in turn. VicPool evolved through a number of design phases and the description given here is based upon the final isolated version of the market which operated between September 1996 and May 1997. The description of the NEM is based upon the intended trading arrangements from May 1998. The current interim NEM1 arrangements in Victoria and New South Wales represent a transitional stage in the development of the national market. In this phase, power is still being despatched separately by the existing market/system operators in each state rather than centrally by NEMMCO.

4.13 Until 1997, VicPool was an ex post market, setting a system marginal price (SMP) retrospectively for each half hour. Generators and demand-side participants submitted bids and offers for a seven day rolling period. The market operator VPX produced regular forecasts for SMP, demand and SMP sensitivities (to changes in the supply/demand balance) for each half hour of the next seven days, as well as for the current day itself. Participants could then make use of this indicative price and demand information by rebidding, the intention of the weekly time horizon being to facilitate price discovery in the run up to the trading day. Bid and offer prices could not be revised beyond the day-ahead stage, but availability could be redeclared at any time subject to conditions set out in the pool rules.

4.14 Like VicPool, the NEM will be a mandatory market. However, prices will be determined on an ex ante five minute basis (as they are currently in NEM1). The market operator, NEMMCO, will run the scheduling program every five minutes for the following five minute period, effectively determining the real-time system marginal price during that period. Any deviations from the projected schedule within the five minutes will be addressed via ancillary services. The trading period for settlement purposes will be half an hour, the settlement price being calculated simply as the time-weighted average of the five minute prices over the half hour.

4.15 Generators and demand-side participants will submit bids and offers to NEMMCO at the day-ahead stage for each half-hour of the following day. There will be no opportunity to revise bid and offer prices. NEMMCO will publish forecasts of prices, demand and price sensitivities for the day-ahead, and updates to these every three hours.

New Zealand

4.16 New Zealand's optional NZEM spot market uses ex post pricing. Participating generators and purchasers submit offers and bids for each half hour at the day-ahead stage. Forecast prices are issued at 15:00 on the day-ahead, and NZEM participants are notified of their scheduled quantities. Participants can, however, rebid prices and volumes until two hours ahead of real time. Within two hours, quantities can only be revised for 'bona fide' reasons, such as plant failure, which need to be verified by the Market Surveillance Committee. Forecast prices are updated every two hours.

4.17 The generators' offers are also used for determining plant despatch (on the basis of forecast demand) and calculating the ex post prices (using actual metered demand).

4.18 Bilateral contract volumes are notified to the system operator, and any deviations are settled at the prices emerging from NZEM.

Argentina

4.19 Only generators and large customers can participate in Argentina's spot market. These parties are also free to sign physical bilateral contracts[7]. The distribution companies supplying tariff customers purchase their requirements either at regulated seasonal prices or directly from generators under bilateral contracts[8]. Seasonal prices are set by the government every six months based upon expectations of spot prices[9]. Any differences between expected and actual spot prices are reflected in the following season's prices.

4.20 The spot market determines hourly ex ante energy prices for the day-ahead. These prices may be modified up to an hour before real time if there are significant changes in the supply-demand balance. Generators do not submit their own offer prices instead the market operator, CAMMESA, calculates marginal generation costs using predefined algorithms and fuel prices. Initially, generators were required to provide audited fuel costs but now they have the commercial freedom to bid in their fuel costs every six months, subject to a cap based on reference fuel prices. Similarly, hydro generators determine their own value of water every six months.

4.21 Generators are not penalised for failing to provide scheduled levels of output beyond the revenue foregone.

[7] Customers with a maximum demand greater than 2 MW are obliged to sign bilateral contracts for at least 50% of their demand.

[8] However, distributors with contacts covering more than half their demand must purchase their remaining requirements at spot rather than seasonal prices.

[9] The seasonal prices can be adjusted every three months if significant changes in plant availability or hydrological conditions occur.

California

4.22 The optional PX wholesale market will set ex ante prices for the day-ahead. Generators and purchasers participating in the PX will submit offers and bids for each hour of the following day. Price discovery will be encouraged through an iterative auction process[10]. Market participants will be allowed up to five iterations in which to submit bids and offers. After each iteration, the PX will publish provisional prices and inform participants whether or not their bids have been accepted. A series of activity rules have been designed to discourage gaming between iterations. The final PX auction will determine the ex ante market clearing price and the quantities each participant must buy and sell. These obligations will be firm.

4.23 The PX will submit the day-ahead schedule to the independent system operator, ISO. Non PX participants will submit their preferred quantities to the ISO via scheduling co-ordinators (SCs). Like the PX schedule, all the SCs' schedules must be balanced between generation and consumption. The PX and SCs will be able to submit revised schedules to within one hour of real time, and the schedules may include adjustment bids for on-the-day increases and decreases in demand and generation. The PX plans to introduce an hour-ahead market in order to obtain this final schedule.

4.24 Real time system balancing will be carried out by the ISO via a balancing market based upon the hour ahead adjustment bids. The ISO will also be able to call upon ancillary services to balance the system if these are cheaper than the adjustment bids. An ex post balancing price will be set for each trading period and this will be used to settle any divergences from day-ahead scheduled quantities.

Capacity Payments and security of supply

4.25 In centrally planned electricity systems, security of supply is often achieved by specifying the minimum acceptable margin of generating capacity over peak demand and constructing plant to ensure that this margin is maintained. The costs of keeping this surplus capacity on the system are simply passed on to the captive consumers. In competitive markets, the key question is whether the normal operation of the market can deliver an appropriate level of security or whether additional measures are required.

4.26 There have been a number of different approaches to the security of supply issue within the electricity systems that have been opened up to competition. In England and Wales, and Argentina, generators receive explicit payments for making plant available[11]. However, there are no explicit payments for capacity in many of the other electricity systems which have or are about to be liberalised, including

[10] Iterative bidding will not be implemented initially but it is expected to commence within a few months.

[11] The same situation applies in Spain, the Ukraine and some of the other liberalised South American markets, but in Alberta (Canada) there are no Capacity Payments.

Scandinavia, Australia, New Zealand and California. These systems rely solely upon the energy price as a market signal for new plant developers. In such systems, generators need to set their plant bid prices so as to recover their total costs over their expected hours of operation.

Scandinavia (Nord Pool)

4.27 Nord Pool does not incorporate any explicit Capacity Payments.

4.28 Since it is dominated by hydro plant, Norway's electricity system is constrained by energy rather than capacity – the risk of power disruptions is from lack of water supplies rather than a shortage of installed generating capacity. In dry years, Norway becomes dependent on power imports via the interconnected Nordic network. Sweden, Denmark and Finland all have a relatively high proportion of thermal plant (fossil-fired and/or nuclear).

4.29 Nord Pool spot prices rose sharply in 1996 as a result of low water availability and this led to calls for the introduction of a Capacity Payments mechanism. However, with higher precipitation and lower spot prices during 1997, no scheme has yet been agreed.

Australia

4.30 Neither VicPool nor the NEM incorporate explicit Capacity Payments. However, if there is insufficient generation to meet demand, pool prices are set at the value of lost load (VoLL), which, at 5,000 A$/MWh, is consistent with the figure used in the England and Wales Pool. Since all available capacity will be running in these circumstances, VoLL payments are not strictly rewarding availability. Within the NEM, VoLL pricing events may be confined to a particular region.

4.31 Proposals are being considered to increase VoLL substantially to 25,000 A$/MWh following a consultation exercise and consumer survey.

4.32 Following power shortages in Victoria during peak demand periods over the past two summers, the market/system operator VPX has issued tenders for reserve power. The state regulator ORG has announced that the retail companies will pay for most of the estimated 660 MW of reserve power required. Regulatory permission will be needed to pass these reserve costs on to customers.

4.33 When the NEM is introduced, NEMMCO will have responsibility for tendering for reserve, if it is necessary.

New Zealand

4.34 There are no separate payments for capacity within NZEM. Currently, there is no upper limit on market prices. However, New Zealand is likely to have a surplus of generating capacity over the medium term following the commissioning of new gas-fired stations.

4.35 Under the previous trading arrangements, spot prices trebled during a drought in 1992. This experience illustrated the response of consumers and retailers to the price signal. Some utilities achieved load savings of up to 15% through relatively low impact water heating restrictions, efficiency improvements, fuel switching and negotiated reductions by major users.

Argentina

4.36 Argentina's wholesale market does incorporate Capacity Payments, although they have changed in nature since the market's introduction. Initially a capacity ticket mechanism was used to reward the provision of capacity. Currently, generators are paid a fixed unit amount by the wholesale market if they are scheduled for output or reserve during high demand periods, defined as weekday peak and shoulder hours (0500 - 23.00 hours). This unit capacity fee is set by the government and has remained at 10 US$/MW since 1994. The unit amount is adjusted by a locational factor to take account of transmission system reliability. Payments are made on the basis of plant capacity net of bilateral contract cover.

4.37 Unscheduled thermal plant are also rewarded for availability in the peak and shoulder hours via thermal base reserve payments. These are designed to ensure security of supply when hydro resources are scarce, the base capacity of a thermal station being defined as its expected output during exceptionally dry years. The price paid for thermal base reserve capacity is currently also 10 US$/MW.

4.38 Since payments are weighted towards peak hours, the system provides some short and medium term signals regarding plant availability.

4.39 All power purchasers pay into a power fund from which the generators are remunerated. Purchasers' Capacity Payments are based partly on units consumed during the weekday peak and shoulder hours, and partly on maximum demand.

4.40 The wholesale market also incorporates a mechanism to push up marginal spot prices when there is a shortfall of generation relative to demand. The market operator CAMMESA introduces dummy "failure units" into the schedule with bid prices related to the value of lost load and the proportion of load lost. In order to give participants an opportunity to adjust their behaviour, CAMMESA informs the market a week ahead if it believes there is a risk that the dummy units will set prices because of a generation shortfall. The value of lost load is fixed by the government and is currently 1,500 US$/MWh, substantially below the VoLL in the England and Wales market (approximately 4,300 US$/MWh).

California

4.41 The Californian PX market has no explicit payments for capacity.

Transmission losses and constraints

4.42 Transmission losses increase with the distance between generation and consumption. Thus, it may be cheaper to schedule a relatively expensive power station located close to a demand centre instead of a more remote station with a lower offer price. Transmission constraints arise whenever network capacity is not sufficient to meet all transmission requirements, such that more expensive generation in favourable locations has to be scheduled in place of cheaper generation behind the constraint. The magnitude of losses and constraints will vary both over time and over different parts of the system according to the pattern of flows on the network. Overall, the cost of transmission losses and/or constraints may be much more significant in some electricity markets than others. This has influenced the way in which transmission effects are incorporated in the wholesale pricing mechanism in the different markets considered in this paper.

4.43 The main market design issue in relation to transmission losses and constraints is the extent to which wholesale market prices vary by location. Marginal pricing of losses and constraints resulting in different prices for each network connection point, or node, in each time period is termed nodal pricing. Zonal pricing aggregates these nodes into larger areas within which prices are equal. Alternatively, the wholesale market may not incorporate any locational variation in prices. Under this option, the costs of losses and constraints maybe averaged and recovered from market participants through a common uplift charge.

4.44 Another issue when locational loss factors are taken into account is whether these should vary dynamically based on the actual power flows in each trading period or be fixed in relation to the typical flow pattern in a given season or time of the day. Moreover, loss factors can be calculated either on a marginal or average basis. Since marginal losses are greater than average losses, marginal loss pricing leads to a surplus of funds being collected. This can be used by the grid company to reduce transmission charges or fund investment.

4.45 Typically, a constrained-on plant, which has been called upon to increase its output purely due to a transmission constraint, is compensated by being paid its bid price. In some markets, this plant would also set the system marginal price. However, there is less consensus in the treatment of constrained-off plant whose output has been reduced by the presence of a transmission constraint. Such plant are compensated for being unable to export power in some systems, such as England and Wales, but receive no payments in others.

Scandinavia (Nord Pool)

4.46 The treatments of losses and constraints currently differs between Norway and Sweden, although a more consistent approach may be adopted in the future.

4.47 In Norway, the system operator, Statnett, checks whether the power flows resulting from participants' day-ahead production schedules are feasible given the constraints of the transmission network. If the projected flows do not exceed the physical capability of the network, the Nord Pool system price is used as the market price for the whole country. If constraints do have an impact, the Norwegian market is divided into zones according to the location of the constraints. The number of zones is thus not fixed but is typically between two and five, including Sweden. The market price within each zone is then adjusted such that demand and supply balance in each region, whilst allowing maximum power flows across the constrained lines. Thus, the price in a zone with a surplus of power is reduced to stimulate higher purchases and lower sales within the zone, whereas the price is raised in a region with a power deficit. Nord Pool sales and purchases within each zone are settled at the regional price. There are no payments to constrained-off generators.

4.48 When there is regional differentiation in prices, Nord Pool will collect more money from purchasers than it pays out to sellers – this surplus is collected by Statnett. Market participants with bilateral contracts between zones pay Statnett a constraint fee based upon the price differential between the two areas and the volume of power traded. The overall income which Statnett collects due to grid constraints is used to lower transmission use of system charges. Income from interconnnector constraints between Norway and Sweden is shared between the two countries.

4.49 Statnett charges for transmission losses through a zonal energy fee. This fee is calculated from the Nord Pool spot price and marginal loss factors, which are set for five geographic zones and three different time periods.

4.50 In Sweden, the system operator recovers the cost of transmission constraints and losses through its grid charges. The Nord Pool spot price therefore applies uniformly across the country even when constraints arise.

Australia

4.51 The significant transmission constraints in the Australian NEM are mostly between states, the networks within individual states being relatively unconstrained.

4.52 Since there are few grid constraints within Victoria, the VicPool market had no explicit mechanism for the treatment of constraints. Transmission losses were allocated to VicPool purchasers via static marginal loss factors applied to each grid connection node. Locational loss factors were not applied to generation in VicPool.

4.53 The NEM will use a zonal pricing system to cope with transmission constraints. If constraints arise on the interstate transmission lines, market prices will diverge between the regions. The clearing price in a region will be set by the marginal generator in the region, allowing for the maximum power flow on the interconnector.

4.54 The NEM will treat inter-regional transmission losses differently to losses within a region. Inter-regional losses will be handled dynamically with the marginal cost of interconnector losses explicitly included within the scheduling algorithm. Within each region, NEMMCO will determine static marginal loss factors for each grid connection node on an annual basis. These loss factors will reflect the amount of power required at the regional reference point to supply 1 MW of power at each connection node. Unlike VicPool, losses will be applied to both generation and demand, and so the prices generators receive will differ both within and between states according to location and the occurrence of transmission constraints.

New Zealand

4.55 The majority of New Zealand's generation is from hydro plant located on the relatively unpopulated South Island, whereas demand is concentrated on the North Island. The capacity of the high voltage interconnector between the two islands is 1300 MW from south to north but flows are restricted below this level due to reserve requirements. The interconnector transmission constraint has a significant impact upon the operation of the system. Transmission losses are also relatively high in New Zealand.

4.56 New Zealand's wholesale electricity market is characterised by its adoption of full nodal pricing. The marginal costs of transmission losses and constraints are reflected in the half-hourly ex post market prices calculated for each of the connection points on the network. There are 477 unique energy prices established in each half-hour although many of these prices are not relevant to pool traders[12]. Generators remote from major loads or behind a transmission constraint earn a lower price at their connection node compared to generators located close to major demand centres.

4.57 Constrained-on payments are paid to scheduled generators whose offer price turns out to be higher than the nodal ex post price, but these payments have not proved to be significant. There are no constrained-off payments to generators who did not run despite bidding below the ex post nodal price (apart from payments to plant scheduled to provide reserve). However, generators can raise such cases with the Market Surveillance Committee.

4.58 The marginal pricing of losses and constraints within NZEM results in a surplus of funds being collected, which is passed on to the system operator, Trans Power. Bilateral market participants trading outside NZEM pay Trans Power directly for losses and constraints via a charge based upon the volume of power traded and the

[12] Many of the nodes relate to transmission equipment, such as transformers. Only approximately 250 nodes are injection or offtake nodes.

price differential between the generation and supply nodes. Trans Power uses these funds to lower its use of system charges.

Argentina

4.59 Argentina's wholesale market uses a dynamic nodal approach to pricing transmission losses. Market prices are set at a central reference point and then adjusted by loss factors for each connection node. The market operator CAMMESA determines the nodal loss factors for each hour. These are applied to both generation and consumption.

4.60 If transmission constraints arise, spot prices at the affected nodes diverge. Constrained-on plant are paid their marginal costs and can set the spot price for the node. The difference in marginal prices between nodes separated by a constraint leads to a surplus of payments being collected. This provides a source of funds for reinforcing the transmission network to relieve the constraint. A constrained-off plant is not compensated for its loss of output, thereby providing an incentive for the generator to contribute towards network investments.

California

4.61 Transmission constraints will be priced zonally in California. Having received day-ahead schedules from the scheduling co-ordinators (SCs), including the PX market, the ISO will check the feasibility of the aggregated schedule given the constraints on the network. If constraints do arise, the ISO will revise the schedules using the adjustment bids in order to achieve a feasible despatch, subject to the condition that each SC's schedule remains in balance. This will give rise to zonal price differentials. All SCs sending power across a constraint will pay the ISO a transmission congestion charge based on the day-ahead zonal price differential. Divergences on the day will be priced in the ISO's balancing market. The surplus of funds collected by the ISO will be passed on to the relevant transmission system owner and used to reduce network charges.

4.62 Each SC will be responsible for the transmission losses allocated to it by the ISO at the day-ahead and hour-ahead stages. Divergences will be settled at the prices set in the ISO's balancing market. The allocation of losses will be based upon the nodal pricing of average (rather than marginal) losses for generation.

Plant dynamics, bid formats and despatch risk

4.63 This section focuses upon plant dynamic constraints and the allocation of risks and responsibilities between generators and the market/system operators. Certain types of generating plant can be operated much more flexibly than others. For example, hydro plant and open cycle gas turbines can be started up relatively quickly whereas large thermal units may take many hours to synchronise with the system and then increase their output to full load. Thermal plant may also incur significant start-up costs in terms of fuel burn and power imports from the grid. Nuclear plant are

typically highly inflexible, and are generally only switched off for maintenance or refuelling. The trading rules may differentiate between plant types explicitly (such as by having specific rules for hydro or nuclear plant) or implicitly (such as through the treatment of start-up costs and despatch lead times).

4.64 A variety of approaches to bidding structure have been taken in the different markets round the world, reflecting, to some extent, their differing plant mixes but also their different philosophies with regard to the establishment of trading arrangements. For example, the hydro dominated Nord Pool market incorporates simple price/volume offers by generators which need not refer to particular plant but have to be regional. In other markets, generators submit complex offers for each plant including technical dynamic limitations, as in England and Wales[13]. By including start-up costs and dynamic constraints in the price setting algorithm, prices in any given trading period will be dependent on the running order of plant during the rest of the day.

4..65 Simple price/volume offers require generators to internalise the structure of their production costs, e.g. start-up and no-load costs, and the technical constraints of their plant. To produce an offer which reflects its average production costs, the generator will have to estimate for how long the plant is likely to be scheduled. Plant likely to be near the margin may also have to tailor their offers to take account of factors such as their minimum technical generation level and minimum runtime. However, markets with simple price/volume offer formats may provide generators with greater flexibility in other respects – such as the ability to submit different offer prices for each trading period rather than a single set of prices for the day (as is often the case in markets with more complex formats).

4.66 There has been a debate in many electricity markets over the extent to which decision-making should be centralised with the market or system operator. Some electricity markets give generators the commercial freedom to decide when to start up and shut down their units. In return, the generators bear the costs and benefits resulting from these decisions. Self-commitment entails giving generators the right to choose when to synchronise with the system and increase their output to a specified minimum level, after which they become subject to central despatch by the system operator. Self-despatch implies complete operational flexibility for the generator. In other markets, the system operator instructs scheduled generators when to start up in accordance with notified lead times.

Scandinavia (Nord Pool)

4.67 Nord Pool market participants submit simple price/volume offers and bids for each hour of the day. These need not relate to any particular group of generating sets, although their location may be significant in the event of transmission constraints. Generators do not provide Nord Pool with any technical plant information such as start-up costs or minimum run times.

[13] Generators' offers in the England and Wales Pool include start-up costs, no-load costs and incremental costs as well as technical data such as maximum rates of change in output and the notice time required to synchronise with the system.

4.68 On the day itself, generators self-despatch taking into account their commitments under bilateral contracts and Nord Pool trades, as notified to the system operator.

Australia

4.69 The format of generators' offers in VicPool was relatively similar to that in England and Wales. Each generating set submitted a daily price curve consisting of up to ten incremental prices (compared to three in England and Wales) and a half-hourly availability profile with a minimum generation level. However, unlike England and Wales, VicPool did not explicitly include start-up and no-load costs. From 1996, generators were allowed to determine when to synchronise to the system. Self-commitment was mandatory for generators unable to synchronise within 30 minutes of a despatch notice from the system operator.

4.70 VicPool also made a special provision for situations of excess generation, when the output of stations operating at their minimum generation levels exceeded demand. The generators' offer structures included two offloading prices. These represented the level of compensation the generator would require for reducing output. The offloading prices therefore provided the system operator with a means to determine which plant to turn down. The compensation paid to this plant was collected from the generators remaining on the system in proportion to their output.

4.71 The NEM has adopted a similar bidding format to VicPool. Generators will be able to self-commit and synchronise with the system at their minimum generation level. The self-commitment level of output will be included in the generators' daily offers, together with up to ten incremental prices for output above this level. Although these offer prices will apply to the whole day, the volume included within each price band can be varied by the half hour, as can overall plant availability. There is no provision for start-up and no-load costs, but ramping rates[14] will be taken into account within each five minute schedule. Plant with commitment times of less than 30 minutes will continue to be centrally despatched. As in VicPool, NEM will have specific arrangements to deal with situations of excess generation. The offer formats will allow generators to submit a range of incremental offloading prices in the form of negative bid prices.

[14] Ramping rates define the maximum rate of change of output of a plant.

New Zealand

4.72 Participants' submissions to NZEM consist of simple price/volume offers and bids for each half hour. These are specified for each grid connection node and can include up to five price bands for generators and up to ten for purchasers. There is no explicit treatment of start-up and no-load costs but ramping rates are taken into account within the scheduling algorithm. The system operator seeks to optimise despatch within each half hour and operational decisions over longer time horizons are solely the responsibility of market participants. Generators therefore self-commit.

Argentina

4.73 In Argentina, generators' offer prices are determined by the market operator CAMMESA on the basis of the seasonal fuel prices submitted. CAMMESA is responsible for plant scheduling and despatch.

4.74 Start-up payments are made to nuclear and steam plants according to the numbers of hours the station has been shut down and a capital recovery factor. The latter is intended to remunerate capital invested due to plant wear and tear. Plants which shut down without being instructed to do so by CAMMESA are required to pay the start-up costs of stations coming on in their place.

California

4.75 Generators participating in the day-ahead PX market will submit a single price/volume curve for their portfolio for each hour. Start-up and no-load costs will not be explicitly included. The intended iterative rebidding process is meant to allow generators to establish plant output profiles which satisfy their technical constraints.

4.76 California's much debated new market structure is intended to minimise the requirement for centralised economic decision making. As a result, there are several constraints on the system operator's flexibility in running the system. Some observers have argued that these measures will prevent least cost despatch, whilst others believe that efficient outcomes will be achieved as a result of the commercial incentives acting on market participants.

Role of demand

4.77 In centrally planned electricity systems, demand tends to play a relatively passive role in the scheduling process, with generating units being despatched to meet an aggregate demand forecast. Most competitive wholesale trading systems have introduced measures to increase the participation of the demand side in the market mechanism. Generally, however, the majority of final consumers in these markets have not been exposed to power price movements in the short term and typically only large energy-intensive industrial customers have actively managed their load profile in response to the electricity price.

4.78 Market operators typically post provisional prices ahead of time. These will either be forecasts of the ex post price or firm ex ante prices to which uplift or balancing market charges will be added after the event. Having seen the indicative prices, customers have the option of adjusting their consumption levels.

4.79 The role of the demand side has been incorporated more formally within some wholesale market mechanisms. In the scheduling process, price responsive demand can be treated either in absolute terms or in relative terms (as a load reduction from a previously specified level). Some ex ante markets require purchasers to submit price and quantity bids in an analogous manner to generators. Rather than using a centrally produced demand forecast, the market demand curve is derived by aggregating these purchase bids. In such markets, the ex ante price is determined by the intersection of the aggregate supply and demand curves. If their bids are accepted, purchasers will have a firm commitment to buy their specified bid volumes at this market price. Any deviations from these volumes on the day due to demand forecasting errors will be settled through the balancing mechanism.

4.80 An alternative approach is to schedule voluntary demand reduction bids as negative generation, as is done in the England and Wales Pool. Under this approach, only those participants willing to shed load actively bid into the market, submitting prices for specified demand reductions. All other electricity consumption is typically represented by a centrally produced demand forecast. If a load reduction bid is scheduled, the market price may be set by a demand side bidder rather than a generating unit.

4.81 Firm purchase commitments cannot be made in wholesale markets where the price is set ex post.

Scandinavia (Nord Pool)

4.82 Demand and supply are treated identically within Nord Pool. Participants bid their net purchase requirements in the form of price and quantity curves for each hour of the following day. Accepted bid volumes become firm purchase commitments at the ex ante market price. Demand side participants can also submit bids to the within day balancing market if they are prepared to adjust their consumption levels within 15 minutes.

Australia

4.83 In VicPool, demand side participants could submit load reduction bids using the same format as generation offers. If scheduled, a demand reduction bid could set the ex post market price. The market operator VPX issued a centralised demand forecast. Neither generators nor purchasers made firm volume commitments at the day-ahead stage since prices were determined ex post. However, difficulties in disseminating information to consumers limited their participation in the market.

4.84 NEM will treat demand in a similar fashion to VicPool. Demand side participants will be able to voluntarily submit load reduction bids which may set market prices. Purchasers will not submit firm volume bids.

4.85 Victoria and New South Wales recognise the need to develop the role of demand in the electricity market because of the very peaky shape of electricity demand in both states[15]. This means that load reduction can often be the most effective method of preventing price spikes.

New Zealand

4.86 Purchasers bid prices and volumes into NZEM for each half hour at each connection node. Together with the generators' offers, these are used to calculate forecast prices. However, the bid volumes are not firm and there is currently no provision for demand side participants to set the ex post market price through load reduction.

4.87 A working group is considering the potential for including demand reduction bids within the despatch and price setting process.

Argentina

4.88 The demand side plays no active role in Argentina's wholesale market and cannot set prices via load reduction.

California

4.89 The day-ahead PX market will treat demand and supply equally. Participants will bid in prices and volumes for each hour. The market clearing price will be set by the intersection of the aggregate supply and demand curves. Accepted purchase bids will become firm, with deviations being settled in the balancing market.

[15]The top 10% of demand is concentrated into 1% of the time.

5. TRADING OUTSIDE THE POOL

5.1 This chapter examines the possibilities for trading outside the primary wholesale power exchange in each of the liberalised electricity markets we are considering. In a mandatory market, such as that in Australia or England and Wales, all electricity has to be bought and sold through the spot market[16]. Nevertheless, players may be able to reduce their exposure to this market through financial instruments such as Contracts for Differences (CfDs), and markets for these instruments can develop independently of the spot market. In England and Wales, for example, only a very small percentage of the power traded in the Pool is not hedged financially by some form of bilateral contract. Financial power contracts are discussed further in the next chapter.

5.2 If participation in the wholesale market is optional, players can choose to sign physical bilateral contracts for all or part of their selling and purchasing requirements. These contracts are notified to the system operator so that the bilateral volumes can be included in the scheduling process. The spot market is then used to clear any residual trades.

5.3 Optional power pools also give players the opportunity to establish alternative market mechanisms if they are dissatisfied with the present trading arrangements. This, it is argued, leads to greater innovation and exerts pressure on the central market operator to respond to the needs of industry participants.

5.4 The operation of an integrated electricity network incurs system costs relating to transmission losses and constraints, and system support costs such as frequency and voltage control (these support services are known as 'ancillary services'). Markets with optional pools have sought to ensure that all system users make an appropriate contribution towards these common system costs, whether or not they trade in the pool.

5.5 System costs aside, markets with optional pools also require mechanisms to deal with divergences between bilateral players' actual and scheduled quantities. In systems where the optional primary market sets an ex ante price, a secondary within day market may be used to settle contractual imbalances. Players with physical contracts may also be able to participate directly in the balancing market. In systems with ex post optional markets, divergences can be cashed out at the pool price.

Scandinavia (Nord Pool)

5.6 Nord Pool's day-ahead spot market accounts for around a fifth of electricity consumption in Norway and Sweden. Although the majority of power is still traded under physical bilateral contracts, spot market volumes have grown steadily since the liberalisation of the Norwegian market in 1991, as shown in Table 6.

[16] There may be limited exceptions for small generators.

Table 6 Nord Pool Trading Volumes

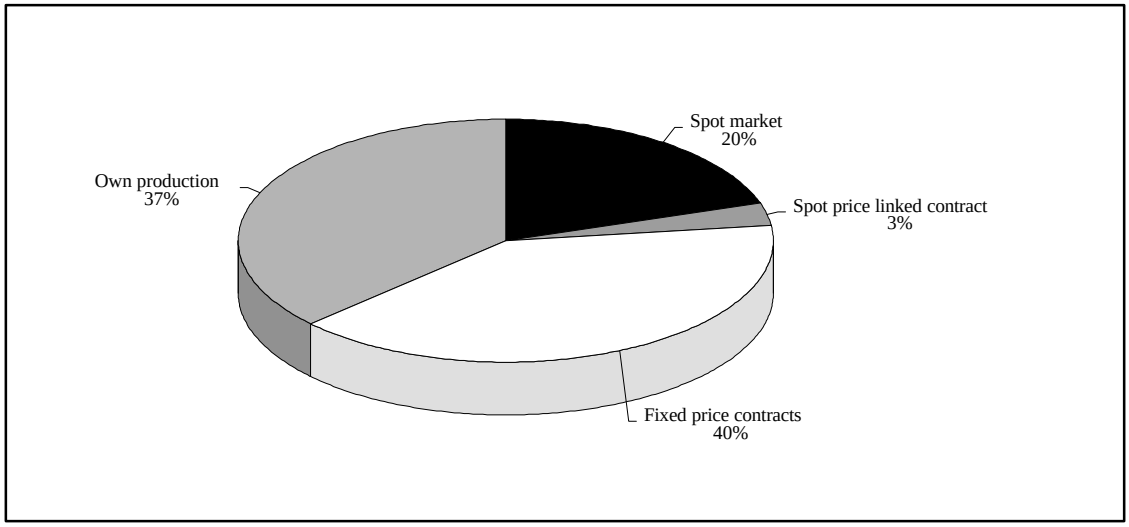
	1993	1994	1995	1996	1997
Spot market (TWh)	10.2	14.8	20.0	40.6	43.6
Balancing market (TWh)	5.6	6.1	5.5	5.9	n/a
Total market (TWh)	15.8	20.9	25.5	46.5	43.6
Demand covered (%)	15.3%	19.2%	23.0%	18.5%	

Note: Except for the balancing market, data includes Sweden as well as Norway from 1996

5.7 Many Norwegian power companies signed long term bilateral contracts prior to liberalisation. However, since 1991 there has been a continuing trend towards shorter term physical contracts and spot trades. There has also been a substantial increase in the use of financial contract instruments. These are traded both over the counter and through Nord Pool's futures exchange (discussed further in Chapter 6).

5.8 As shown in Figure 1, Norwegian electricity suppliers currently source 40% of their physical purchasing requirements under fixed price bilateral contracts and a similar proportion from their own production facilities. Physical contracts linked to spot market prices account for 3% of suppliers' purchases.

Figure 1 Power Sources For Norwegian Suppliers



Source: NVE Electricity market survey 1997

5.9 Generators notify the respective system operators in Norway and Sweden of their intended generation profiles at the day-ahead stage, taking into account their commitments under physical bilateral contracts and Nord Pool trades. Participants then self-despatch to meet these commitments. Any divergences between the notified quantities and actual metered volumes are settled at the prices emerging from the balancing markets in each country. Market participants with bilateral contracts trading between transmission constrained zones in Norway pay the system

operator Statnett a constraint fee based upon the spot price differential between the two areas and the volume of power traded.

Australia

5.10 Mandatory participation is a feature of both VicPool and NEM. All generation from stations with capacity greater than 30 MW must be sold into the wholesale market. Thus, there are no arrangements for physical bilateral contracts outside the pool.

New Zealand

5.11 In theory, market participants can trade power outside NZEM under physical bilateral contracts. There is no legislation governing NZEM and membership is not mandatory for market participants. Users of the transmission network need only meet the system operator's technical standards for connection. In practice, however, the major generators sell all their power through NZEM. The majority of generation is still state owned.

5.12 Trans Power, the system operator, and EMCO, the market operator, have put in place arrangements to ensure that all system users contribute towards the costs of scheduling and despatch, whether or not they trade through NZEM.

5.13 Participants that opt to trade bilaterally must inform Trans Power of their contractual volumes. Any divergences between the notified and metered quantities are settled at NZEM prices. Trans Power recovers the cost of transmission losses and constraints from those trading outside the pool via a charge based upon the differential between NZEM nodal prices at the injection (generation) and offtake (supply) nodes involved and the volume of power traded. Bilateral and NZEM trades are treated equally for the purposes of attributing the costs of ancillary services.

Argentina

5.14 Although generators are free to sign bilateral contracts with large consumers and distribution companies, all power is physically despatched by the wholesale market operator, CAMMESA. As a result, generators may be despatched to provide more or less energy than that covered by contractual commitments.

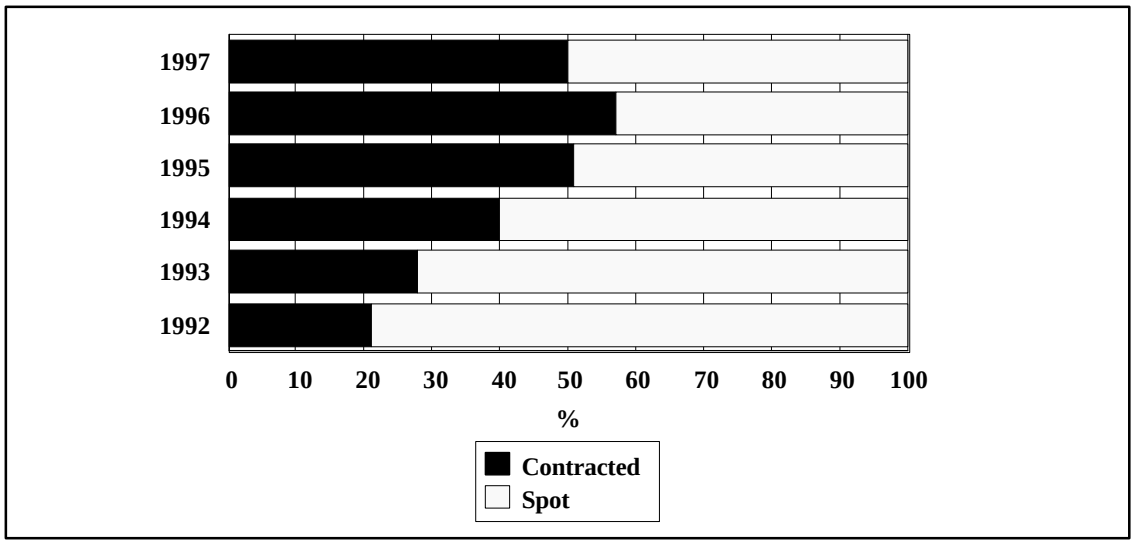
5.15 The bilateral contract volumes are reported to CAMMESA for use in the wholesale market settlement process. The contract volumes are deducted from the metered generation and consumption that have to be settled by the parties concerned. Residual quantities are then settled by CAMMESA. Generators are paid the hourly spot price for any production in excess of their contractual volumes, and pay spot prices for any net purchases. Large consumers also settle at the spot price but distribution companies settle at the administered seasonal prices.

5.16 Capacity payments to generators are made on the basis of plant capacity net of bilateral contract commitments. Bilateral contracts must define injection and

'offtake' nodes such that transmission loss factors and constraint costs may be applied.

5.17 The details of bilateral contracts are made publicly available. Only privately owned generators are permitted to sign contracts directly with customers or distributors. As illustrated in Figure 2, the proportion of sales covered by bilateral contracts increased steadily from around 20% in 1992 to almost 60% in 1996. Since 1992, the majority of generating assets have been privatised and the competitive threshold for large customer participation has been lowered.

Figure 2 Relative Proportions Of Spot And Contract Trading Volumes



Source: CAMMESA Boletin del MEM

California

5.18 California's new market design is intended to maximise competition and choice. Participation in the PX wholesale market will therefore be voluntary, although the three large vertically integrated utilities are obliged to trade all their power through the pool until 2002. These companies currently account for the majority of the state's generation output, but all three are now in the process of selling off most of their generation assets.

5.19 All other market participants will be free to sign bilateral contracts or trade on any alternative power exchanges which emerge[17]. These participants must appoint a scheduling co-ordinator (SC) to interact with the system operator (ISO) on their behalf. Any divergences from notified bilateral contract quantities will be settled at the ex post prices set in the ISO's balancing market.

5.20 No distinction will be made between PX and non-PX participants for the purposes of allocating costs for transmission losses, constraints and ancillary services. All SCs,

[17] A scheduling co-ordinator known as the Automatic Power Exchange intends to set up a weekly market in competition to the PX.

including the PX, sending power across a constraint will pay the ISO a transmission congestion charge based on the PX day-ahead zonal price differential. The ISO will also be responsible for allocating transmission losses between SCs. Ancillary services will either be provided by SCs or purchased from the ISO.

6. FINANCIAL CONTRACTS AND TRADING

6.1 This chapter focuses on the development of financial, as opposed to physical, contracts. Market participants may use financial contracts to hedge their exposure to the volatility of short term power prices, regardless of whether the wholesale pool is mandatory or optional. Financial contracts may be negotiated bilaterally or traded on an organised exchange. The duration of contracts can vary from a few hours to over ten years for a new power station project.

6.2 The contracts for differences (CfDs) developed in the England and Wales market were the first purely financial instruments in the world to be introduced for managing risks related to electricity trading. Such contracts do not allow for the physical delivery of electricity but are instead settled in cash against a reference power price. In England and Wales, the half-hourly Pool Purchase Price is most commonly taken as the reference price.

6.3 Longer term financial instruments, such as CfDs, are invariably struck bilaterally with a specification tailored to meet the particular needs of the parties involved. Over shorter timescales, such as within a year, standardised risk management products have been introduced in many markets to facilitate trading among a wider range of participants. Such products may be listed on a futures exchange or traded bilaterally over the counter (OTC), either directly or via a broker. Exchange-traded futures contracts offer the advantages of price transparency, anonymity and minimal counter-party credit risk. OTC products generally offer more flexibility in terms of contract specification, and do not usually require margin payments to be made before the contract matures[18].

6.4 Since financial contracts are not conditional upon physical delivery of electricity, such products facilitate the entry of non-industry players such as brokers, banks and trading houses. This, in turn, may broaden the range of risk management options open to the established players, as well improving market liquidity.

Scandinavia (Nord Pool)

6.5 Nord Pool pioneered the world's first electricity futures exchange and trading volumes have grown steadily since the market's launch (see Table 7). In 1996, Nord Pool's futures turnover surpassed sales in the underlying Nord Pool spot market for the first time.

[18] Futures exchanges typically require margin payments before contract expiry in return for guaranteeing the settlement process. There is an initial payment reflecting the historic volatility of prices and a daily payment which covers the difference between the contract price and the prevailing market price.

Table 7 Nord Pool Futures Trading Volumes

	1993	1994	1995	1996	1997
Futures market (TWh)	2.6	7.1	15.4	42.6	52.8

6.6 The Nord Pool futures market, Eltermin, allows participants to secure a price for power up to three years ahead. Contracts are traded as single weeks for the next four to seven weeks, as blocks of four weeks up to a year ahead and as seasons one to three years in advance. Liquidity is concentrated in the trading of flat contracts, with most activity focusing on the shorter term contracts. The seasonal contracts lack liquidity, particularly compared to the OTC market. Nord Pool's product range also includes peak load contracts (weekday daytimes) but off peak contracts (covering weekends and nights) were discontinued in September 1996 due to low turnover.

6.7 Nord Pool futures contracts were originally settled physically but they changed to financial settlement in September 1995. Contracts are struck against the Nord Pool system spot price. This leaves players exposed to regional price differentials in the event of transmission constraints, although this risk can be hedged in the OTC market. Telephone trading on the futures exchange was replaced by an electronic trading system in November 1996. Nord Pool has set up a help desk to serve participants who do not have direct access to the trading system.

6.8 OTC trading is also very active, with bilateral contract turnover three to four times that on the Nord Pool exchange. In 1996, OTC sales were estimated to be 160 TWh. Several brokers and traders participate in both the Nord Pool and OTC markets. Broking competition is fierce, with about 15 firms competing. Due to the large number of participants, credit risks can be significant in the OTC market and there have been a handful of bankruptcies. Consequently, since 1996, Nord Pool has offered a clearing service for contracts entered into outside the exchange. Clearing services such as this guarantee OTC contracts for a fee.

6.9 Nord Pool has recently replaced the seasonal futures contract with cash-settled forward contracts in order to improve liquidity in exchange trading of contracts with longer maturities. Margin payments are not required for the forward contract, which should ease cashflow constraints on longer term trading.

Australia

6.10 Due to the mandatory nature of the Australian wholesale electricity markets, all contracts must be financial. Initially, the size of the Vesting contracts between generators and retailers left little room for futures markets to develop. These contracts are gradually winding down as the retail market is being opened to competition.

6.11 Liquidity in OTC contracts has improved over the past two years, although it appears that trading volumes involving non-generator participants have been low. These

consist mostly of cash-settled swaps and call options[19]. During 1996, the Sydney Futures Exchange (SFE) considered setting up a broking service, but this has not emerged.

6.12 However, after wide consultation, and in the light of the emerging NEM, the SFE did launch two futures contracts in September 1997. Due to the transmission constraints between Victoria and New South Wales, one contract was launched for each market. The format of these futures is a monthly contract for a flat 500MW, traded for up to 12 months ahead, and settled against the monthly average spot market price in the appropriate market.

6.13 In addition, the national market operator, NEMMCO, is obliged to facilitate a short-term forwards market. This market will trade short-term hedges in the days prior to despatch. NEMMCO is also required to establish an inter-regional hedging market to reduce players' exposure to price differentials between regions. Such hedges may vary in duration from the day-ahead to many years. The details of both these markets are as yet unknown.

New Zealand

6.14 Traditionally, ECNZ has held yearly tender rounds for long-term financial contracts for up to 5 years. There has also been substantial interest and activity in OTC futures contracts over the past few years. Banks began to enter into swaps and options with generators and retailers before the opening of the generation market. By far the majority of these have been cash-settled swaps.

6.15 The New Zealand Futures and Options Exchange launched an electricity futures contract in November 1996. The contract is monthly for a flat 250MW, financially settled at the average spot market price for that month. Settlement prices are based on a single fixed node. Initially, participants could trade contracts for up to six months ahead, but this was extended to 12 months in early 1997.

6.16 Although the first trades did not take place until January 1997, liquidity has steadily improved, and by the middle of 1997 around 80 to 100 contracts a day were traded. One complaint has been that contract is too long relative to the rapid changes in hydrological conditions that can occur. However, calls for shorter contracts have been rejected on the basis that they would reduce liquidity.

Argentina

6.17 The contracts between generators, distributors and large customers are essentially physical, although any differences between a generator's contractual volume and actual output are settled in the wholesale market (see Chapter 5).

[19] A swap exchanges a floating price for a fixed price for a specified time period. A call option gives the buyer the right but not the obligation to buy at a specified price within a specified time period in exchange for a one-off premium payment.

California

6.18 A small OTC market has developed in the US since the deregulation of the interstate wholesale electricity market in 1992. Currently, around 90% of OTC trading is physical, with just 10% of contracts settled financially. Deregulation of the Californian market is expected to lead to a large increase in OTC futures, especially between marketers and customers.

6.19 Two electricity futures contracts were listed on the New York Mercantile Exchange (NYMEX) in March 1996. These are physically delivered contracts, with two West Coast delivery points: one at the California/Oregon border and one at Palo Verde, Arizona. Combined trading volumes at the two West Coast delivery points were initially low but increased to 89.1 TWh during 1997. NYMEX plans to launch three new contracts early in 1998, using East Coast delivery points.

6.20 Brokers and power marketers have been quick to enter the market, and data vendors (such as Bloomberg, Dow Jones, Platt's and Reuters) have been competing to provide news and price information to traders. Investment banks are already believed to be active in the market but are not yet major players. These companies have broadened the OTC product range, providing several types of option contracts.

6.21 Commercial banks[20] have been noticeably absent from the list of participants. This is blamed on the physical nature of the contracts. In late 1997, no commercial bank had applied for permission from the Office of the Comptroller of the Currency to take physical positions, as they are required to do if they wish to trade.

[20] Commercial banks are deposit taking institutions whose main business is lending money rather than derivatives trading.

7. COMPETITION IN GENERATION AND SUPPLY

7.1 In most markets, generation is conceived as a competitive activity from the outset but supply competition may be introduced more gradually, as has been the case in England and Wales.

7.2 In two of the markets that we are considering, California and Australia's NEM, competitive trading arrangements have not yet been fully implemented, so it is not possible to discuss the development of competition in them. However, we outline the regulations and market rules that relate to competition.

7.3 Of the markets which are in operation, Norway and Victoria have the longest track records and hence it is these countries that we concentrate upon in discussing the actual development of competition.

Promoting competition in generation and supply

Nord Pool

7.4 With around 30% of capacity Statkraft is by far the largest generator in Norway. In Sweden, Vattenfall and Sydkraft account for 70% of capacity. To date, there has only been limited entry into the generation market in either Norway or Sweden principally because there has been little need for new capacity. The building of two 350 MW gas-fired plants in Norway is currently being considered. However, strong environmental concerns have limited the opportunities for gaining planning consent for any new generating capacity.

7.5 From the outset, all customers have been free to choose their suppliers but, apart from some of the largest customers, very few chose to do so initially. One reason was that all customers, irrespective of their size, who wished to change supplier had to install an hourly meter and pay their local network operator a fee. In 1995, the maximum allowed cost of installing, operating and maintaining a meter in Norway amounted to NOK 2,000 (over £150) and the charge for changing supplier was NOK 246 (around £20). Thus, in most cases the costs of changing supplier outweighed any possible reduction in energy charges.

7.6 Recognising this fact, a number of reforms have been made to promote supply competition in Norway. Customers who use less than 500 MWh of electricity no longer have to install an hourly meter. Instead, their hourly consumption is estimated using predetermined load profiles. In addition, from 1997, network operators are no longer allowed to charge customers for changing suppliers.

7.7 Prior to 1997, Norwegian suppliers also had to pay a fee to each local network owner in whose area they had customers. The Norwegian Water Resources and Energy Administration (NVE) believed that this reduced the number of suppliers competing

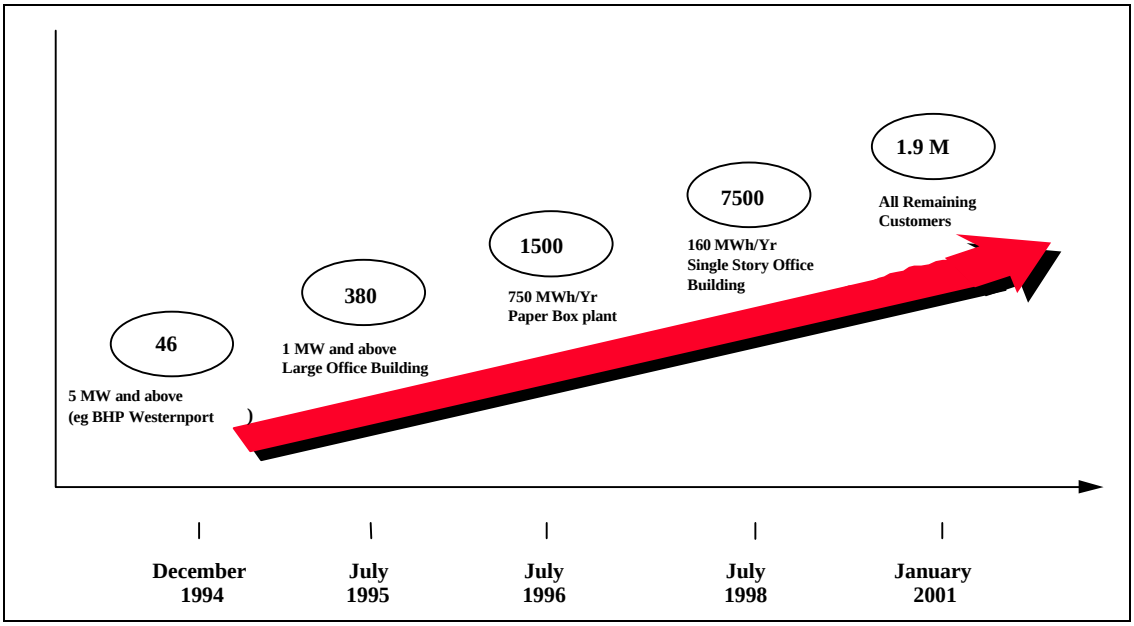
in each region since it encouraged suppliers to target customers in a few regions rather than across the country. The fee has now been abolished.

Australia

7.8 The generation market in Victoria was deliberately set up in an atomistic fashion to encourage competition. Each large-scale thermal plant now has a different owner. There has been no entry into the generation market.

7.9 Supply competition is being introduced in phases in Victoria, see Figure 3. The five regional distributors also act as the main suppliers with monopoly rights to smaller consumers within their licensed areas. In total there are seventeen licensed suppliers, one of whom is also a generator (Yallourn).

Figure 3 Introduction Of Supply Competition In Victoria



7.10 Victoria competition legislation limits vertical and horizontal cross-ownership between distributors/suppliers and generators. The general principle is that persons will be allowed to own or control up to 100% of one licensed Victorian generation or distribution company; 20% of another; and 5% thereafter. There are corresponding prohibitions where the shareholder concerned is a licensed company. Restrictions extend to holding licences, shares in a licensee, exercising effective or management control and to a prohibition against asset acquisitions which would circumvent these primary prohibitions. With the proposed privatisation of Power Net, these restrictions will be expanded to cover ownership in the high voltage transmission company.

7.11 These prohibitions are administered and enforced by the ORG, which has the power to force disposition of, or suspend, voting rights. The cross-ownership prohibitions operate in addition to the prohibitions in the Trade Practices Act.

New Zealand

7.12 Until 1996, the state-owned generator, ECNZ, overwhelmingly dominated generation in New Zealand. In order to introduce competition into generation before the opening of the wholesale market, the government acted in February 1996 to establish a second substantial generating company, also state-owned. The new generator, Contact Energy, was created from the divestment of 22% of ECNZ's capacity. At the same time, ECNZ signed a memorandum of understanding with the government under which it will not build more than 50% of the country's new capacity until its market share falls below 45%. Plans are being considered to further break up ECNZ.

7.13 New entry in generation is occurring. An independent consortium is building a 350 MW CCGT that will be commissioned in 1998. Contact Energy is expanding its capacity by constructing a similar sized CCGT that is also due to be completed in 1998.

7.14 Full retail supply competition has been introduced in New Zealand and there are currently more than 40 retail power companies competing for customers. The majority of these are Electricity Supply Authorities, regionally based distributors and suppliers that previously had monopoly franchise supply areas i.e. they are the New Zealand equivalent of Regional Electricity Companies.

7.15 ECNZ and Contact are not formally prevented from owning retail suppliers. ECNZ and Contact have signed voluntary medium term (5 year) contracts with large customers and distributors/retailers for a substantial proportion of their output.

Argentina

7.16 The restructuring of the Argentinean system required the mandatory separation of the despatch and transmission functions from the generation and distribution functions, as well as the establishment of an independent despatch agency.

7.17 In order to avoid concentration in the generation sector, generation companies are legally restricted to a market share of 10% or less of the national electricity sales volume. They are also prohibited from owning majority shares in electricity transmission facilities. The restrictions on reintegration and cross-ownership are enforced by the national regulator, ENRE.

7.18 Some competition in supply has been introduced. The franchise threshold is currently 100 kW. There are currently no plans to further lower this threshold. Customers in the competitive sector can buy their electricity from regional generators or directly from any of the private sector generating companies.

California

7.19 Market power concerns in California have centred on the dominant position of the three major vertically integrated utilities, Pacific Gas & Electric (PG&E), Southern

California Edison (SCE) and San Diego Gas and Electric (SDG&E). The Californian Public Utilities Commission (CPUC) has attempted to address these concerns in a number of ways.

7.20 The CPUC has required the three major utilities to unbundle their activities into subsidiary companies. The utilities will continue to own and operate their distribution networks but will have to provide non-discriminatory access to them. Distribution services will be regulated. The ISO will control and operate California's transmission system.

7.21 As far as generation is concerned, PG&E and SCE agreed to divest through "spin-off or sale to a non-affiliated entity" at least 50 % of their fossil-fired generating assets. So far, PG&E has agreed the sale of three stations to Duke Energy whilst SCE has announced its intention of selling all its generating assets and has made significant progress in so doing. SDG&E has also chosen to divest plant.

7.22 The three major utilities must sell all their output to the PX, and buy power from the PX to resell to their customers for the first four years of the market. In addition, a distribution company with a generation business will be prohibited from entering into contracts with an affiliated generator until the market structure is fully implemented, all transition costs have been collected and all customers have direct access i.e. for at least four years.

7.23 Full retail supply choice is due to be introduced at the same time as the liberalisation of the wholesale market. There will be three different mechanisms for introducing customer choice. Customers will be able to choose to:

- Install hourly meters and have access to load responsive prices;
- Negotiate (either in customer groups or individually) directly with generators and then arrange for transmission and distribution. This is known as "Direct Access";
- Use a marketer or broker to make Direct Access arrangements on their behalf.

7.24 To facilitate the Direct Access programme of retail supply competition and the aggregation of customers in the competitive market, the CPUC has approved the use of load profiling for customers whose maximum demand is less than 50 kW. Customers with a maximum demand greater than 50 kW must install an hourly meter. The smallest consumers, those with a maximum demand below 20 kW, will participate in Direct Access through load profiling, since hourly meters would not be economic for them. Those customers whose maximum demand falls between 20 kW and 50 kW can chose either to install hourly meters or to accept load profiling. It is expected that, over the longer term, these customers will move to hourly meters. The CPUC has not yet made a decision on whether the utility distribution companies will be the only providers of metering and meter services to the 20 kW to 50 kW customers.

Experiences to date

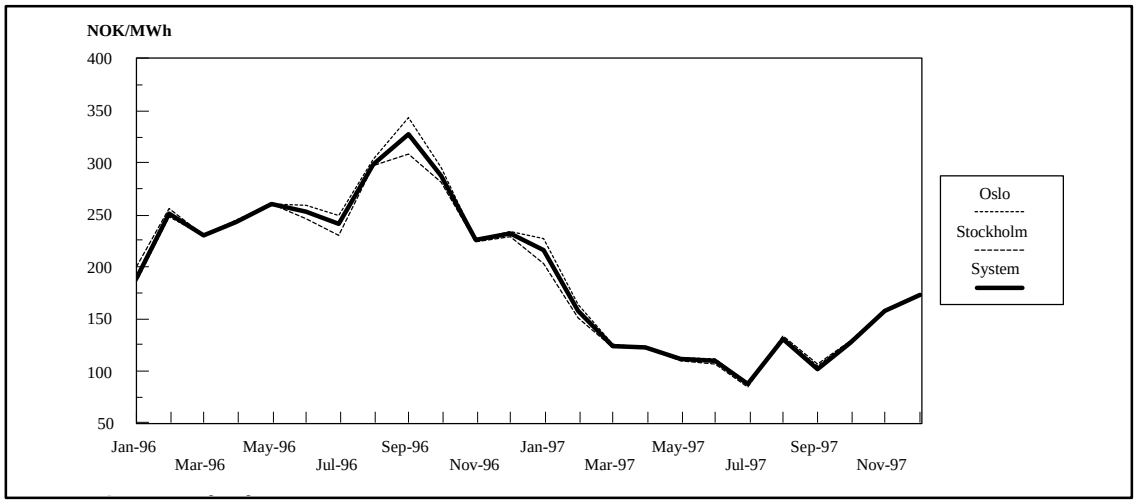
Nord Pool

7.25 Annual price volatility in the Nord Pool spot market can be as high as 400% because of the dependence of the market on hydro power. For example, cold and dry weather in 1996 significantly increased prices in Nord Pool (see Figure 4).

7.26 The price rises in Nord Pool during 1996 prompted some concerns about market manipulation. Commentators suggested that large generators might have withheld water in order to drive up the spot price to ensure a favourable benchmark price against which bilateral contracts could be re-negotiated. There has also been some concern about pricing up bids behind transmission constraints in Norway (though such constraints are relatively rare).

7.27 Higher rainfall levels in 1997 resulted in a sharp decline in prices overall and a reduction in price volatility from the previous year. Consequently, concerns about the functioning of the market have declined.

Figure 4 Monthly Average Nord Pool Spot Market Prices (Elspot)

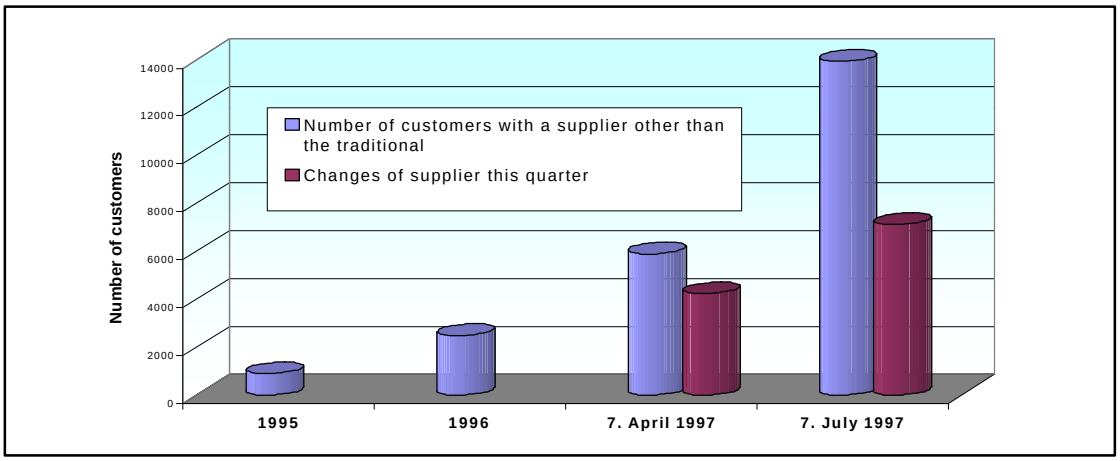


Source: Nord Pool

7.28 The number of participants in the spot market has been increasing in Nord Pool. In January 1997 there were 143 Pool members compared to 98 one year earlier. Eighty-three of these were considered frequent traders – 50 vertically integrated companies, 15 distribution companies and 18 traders, brokers or large industrial customers. By January 1998, Nord Pool membership had reached 199.

7.29 The Norwegian regulator, NVE recently carried out two special surveys, focusing on end user mobility. The results of these are shown in Figure 5.

Figure 5 Supplier Switching In Norway



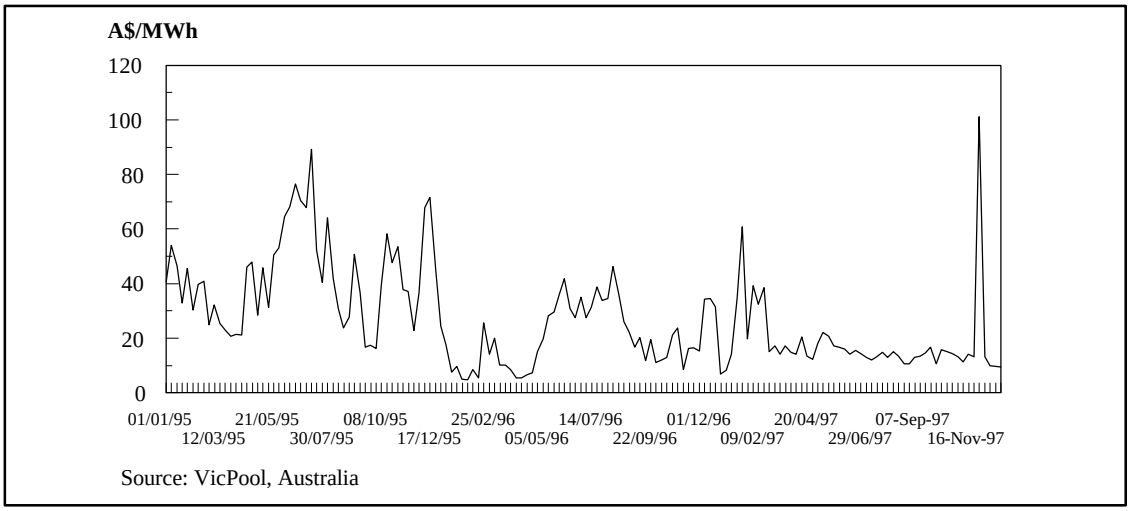
Source: NVE

7.30 In the quarter to 7 April 1997, 4,200 customers changed supplier whilst in the following quarter, 7,100 customers changed supplier. Furthermore, of the 13,900 customers with a supplier other than their local network operator, 81% had changed supplier within the last two quarters[21]. All these figures suggest that supply competition may be increasing. However, these figures need to be viewed in context. Since there are 2 million households in Norway, the percentage of customers changing suppliers remains very low. Over 99% of customers still remain with their traditional supplier, i.e. their local network operator.

Victoria

7.31 Figure 6 shows the weekly average SMP in VicPool from January 1995 to December 1997. Excess capacity in Victoria and New South Wales has led to competition to generate which has tended to depress prices.

Figure 6 Vicpool Weekly Average SMP



Source: VicPool, Australia

[21] Customers may change supplier every week if they so wish.

7.32 Customers in both the competitive and non-competitive sectors of the market have benefited from price reductions since the wholesale market was introduced. For example, from November 1992 to May 1997, the price paid by a typical domestic customer has fallen by 9.2% in real terms.

7.33 A survey, in November 1996, of more than 300 Victorian business by the Australian Chamber of Manufacturers showed that 78% of these customers were paying less for their electricity, with only 10% paying more. The savings ranged between 10% and 40%.

New Zealand

7.34 So far, significant competition has only developed for larger users of electricity. As in other countries, the need for sophisticated and expensive meters has limited the scope for domestic customers to change suppliers. However, retail companies have been investing heavily in metering technology to facilitate competition for smaller customers.

7.35 Three South Island companies have set up the first large-scale retail supply competition trial for residential customers. This began in December 1997 and involves 6,000 households. The trial also involves New Zealand's first use of load profiles to facilitate competition and supplier switching.

Argentina

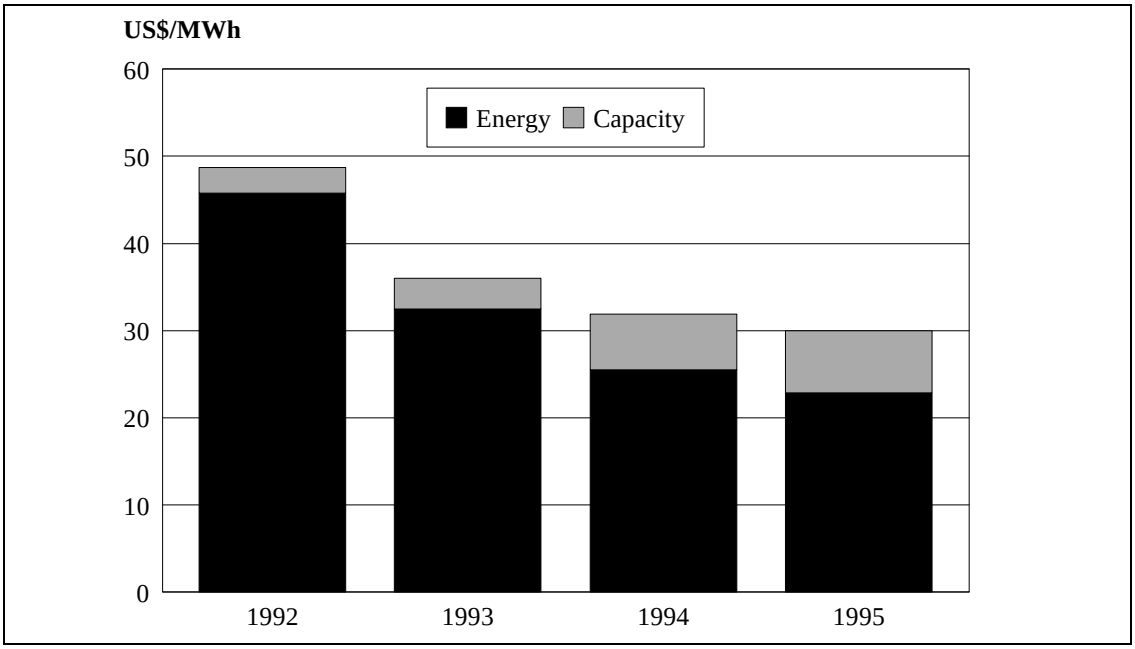
7.36 The total number of participants in the two wholesale markets increased from about 34 in August 1992 to more than 1,200 by November 1997. This has largely been driven by the involvement of large industrial users, of whom there were 1,148 participating in the market by November 1997.

7.37 However, on the generation side there have also been significant developments. The number of generators has increased from 10 to 44, and 11 auto-generators and two co-generators have also joined the market. The installed capacity on the system has increased by 36.5% whilst the output produced has risen by 35%.

7.38 Capacity prices have risen since the privatisation and restructuring of the industry, see Figure 7, but energy prices have fallen significantly. Capacity payments rose between 1993 and 1994 as the unit capacity fee was increased from 5 US$/MW to 10 US$/MW. Since 1994, the introduction of new capacity has led to a further rise in the capacity price.

7.39 Energy prices have fallen partly because the underlying fuel prices have fallen but also because of the lower costs of the new plant entering the market.

Figure 7 Annual Average Energy And Capacity Prices



Source: CAMMESA

7.40 All customers with a maximum demand greater than 100 kW can now choose their suppliers provided that they have an appropriate meter. So far, 1,700 such meters have been installed for above 100 kW customers and a further 100 installations are planned.

California

7.41 As of 1 January 1998 (California's initial deadline for the introduction of retail competition), only 20,000 customers from a potential 11 million had chosen to change electricity supplier. This represents a mere 0.02% switching rate. The delay in introducing retail competition has led to concern that customers may be deterred from switching to new power suppliers.

7.42 Whilst the market has not yet opened and hence Direct Access for customers has not been implemented, the CPUC has ensured there is a mechanism through which customers will benefit from increased competition in the wholesale market. The issue of rate reduction bonds by the existing utilities is intended to allow the utilities to cut rates to captive customers whilst continuing to collect identified (largely sunk) transition costs.

7.43 At present, residential and small commercial customer prices are frozen at their June 1996 levels. The utilities have been allowed to issue bonds that will result in a 10% cut in total electric bills from January 1998. These price cuts will remain in place only until the transition charges are paid off but, in any case, they will not be extended beyond March 2002.

7.44 The bonds will be repaid by an additional charge on residential and small business customers' bills of less than 2 c/kWh beginning no later than April 2002 and

continuing until the bonds are retired in early 2008. By law, customer prices are to decrease by at least 20% after 2002, even taking into account the cost of repaying the bonds.

7.45 The price cut is meant to ensure that residential and small business customers do not have to wait to benefit from the market restructuring. Without a cut, it was feared that such customers would not see benefits as soon as large electricity users. In the long run, it is estimated that the low cost financing provided by the rate reduction bonds could result in net savings to ratepayers of up to $970 million over a 10-year period.

8. TRANSPARENCY

8.1 The main attributes of a market that will influence its transparency are the extent of timely access to relevant market information, the auditability of all its market mechanisms, and its level of complexity.

8.2 Auditability and the availability of information are largely administrative issues, and are not directly related to the structure of the market. In any market there is the opportunity to release information on bids and offers, prices, actual generation, demand, and the detailed operation and rules of the market clearing and/or despatch mechanism. However the commercial objectives of market participants may result in significant pressure for some of this information to be kept confidential.

8.3 Many markets have seen an expansion in the amounts of information made available over time. For example, in 1995 the availability of data on metered generation for plant in Victoria was restricted to the owners of the plant itself. This data is now made publicly available. Indeed, it is now the case, in several of the liberalised electricity markets, that substantially more information is made available than in markets for other commodities.

8.4 The provision of information in the England and Wales Pool is similar to that in other markets. All the data on bids and demand are made available to market participants and interested parties. The Pool has followed a rolling program of releasing additional information. For example, data on actual plant output was made available to non-Pool members for the first time in April 1997.

8.5 The main drivers of market complexity are the despatch and price setting mechanism. Despatch mechanisms that are based purely on matching price/volume bids for generation and supply ensure that each settlement period is treated in isolation. More complex spot markets have included specific provisions for dynamic parameters such as ramping rates and minimum stable generation levels to be bid in and included in the scheduling process. Start-up and no-load costs may also be taken into consideration. Such provisions result in linkages between settlement periods so that prices in one period may depend on what happens in another period.

8.6 The England and Wales Pool has a relatively extensive bidding format, including no-load costs, start-up costs and dynamic parameters. The price setting mechanism spreads no-load and start-up costs over the periods in which a plant is operating.

Scandinavia (Nord Pool)

8.7 Trading in Scandinavia occurs in three markets, each dealing with a different time-horizon: the futures/forwards market, the spot market, and the regulating market. The Nord Pool futures/forwards market provides screen-based trading of medium to long term financial contracts. Trading is conducted anonymously, and only offer prices are made available to all participants. Details of actual traded contracts, such as the counterparties and the contract price and volume are not released. This is typical of the operation of futures markets.

8.8 The Nord Pool spot market is based on a system of simple price and volume curves submitted by both generators and purchasers. This market is cleared hourly without reference to technical or operational plant constraints. If transmission constraints exist, the market is broken into regions. All interested parties have access to spot market prices and total traded volumes. However, participant's bids and offers, and their individual traded volumes, are not made available.

8.9 The regulating market deals with any deviations from the spot market schedule, such as those resulting from technical constraints or demand forecast errors. At this stage, technical and operational constraints that may apply to generation plant are explicitly taken into consideration.

8.10 In the Scandinavian system, transparency is enhanced through the use of three distinct markets, each dealing with a different time period. Complexity is kept to a minimum by only recognising plant technical and operational constraints in the regulating market, which operates over the shortest time frame. However, the availability of information is relatively restricted in each of these markets.

8.11 Historically, data on hydro reservoir levels has not been widely available and this has impacted on smaller players and purely financial traders who did not have easy access to information regarding the physical position of the system. Data on current water levels is now more accessible. There have been calls for the introduction of rules that would oblige players to publish price-sensitive information, such as power exchange agreements with utilities in other countries.

Australia

8.12 The compulsory spot market in Victoria underwent a number of changes to move it towards the structure of the NEM. In its final independent version, participants submited simple bids of price and volume. In the absence of a short term forwards market, price discovery was aided through the provision, by the market operator, of a forecast schedule for the next seven days.

8.13 The scheduling process did not take account of technical constraints such as ramping rates and minimum generation levels. Generators had themselves to ensure a feasible production profile through a notification of self-commitment. Generators could use the forecast schedules for the next seven days to determine their self-commitment schedule.

8.14 Market participants had access to most market information, such as forecast plant availability, forecast schedules, the sensitivity of prices to changes in demand, participant's bids and offers, and actual price data.

8.15 Participants in the NEM will be required to submit simple bids and offers to the physical market, effectively consisting of a price and volume for each half-hourly trading period. The despatch algorithm will be run every 5 minutes of the day but the prices produced will be averaged to produce a single price for each trading period. However, transmission constraints may result in regional price differentials.

8.16 The information provision section of the National Market Code, which outlines the trading arrangements for the NEM, is based on the principle that all market data should be made available unless it is deemed to be commercially confidential. Table 8 summarises the data reporting requirements for the NEM.

Table 8 Data Reporting Requirements For The NEM.

Data made available to all market participants: On a half-hourly basis: Forecast demand and available generation, for the next 7 months Sensitivity of prices to changes in demand All bid/offer data Actual generation On a scheduling period basis: Pre-despatch schedule for the following day Regional reference prices

8.17 All data on bids and offers, regional reference prices, actual generation and demand will be available to all interested parties via an electronic database system. Regional reference prices for each five minute period will be made available within five minutes of the end of the scheduling period. A subset of this information, including regional reference prices and system load by trading period, will be freely accessible to the public via an Internet site.

8.18 NEMMCO is obliged to publish demand and aggregate availability forecasts for each region. These forecasts will extend out for twenty-four months on a daily basis and seven months on an half-hourly basis. To assist in this process, generators will have to provide NEMMCO with estimates of their maintenance schedules.

8.19 Day-ahead price forecasts will also be produced by NEMMCO. These will include estimates of the sensitivity of prices to a range of changes in plant availability or demand.

8.20 It is also intended that a short-term forwards market and an inter-regional hedging market will be set up. The market rules specify that the clearing prices and quantities traded in these markets will have to be published.

8.21 The NEM rules explicitly provide for an annual audit of market mechanisms. This will include an audit of the scheduling and despatch process, and a report to all market participants.

New Zealand

8.22 Participants in the NZEM, submit simple bids and offers consisting of price and volume at the day-ahead stage. A despatch model that uses nodal pricing is used to determine the schedule.

Table 9 Data Reporting In New Zealand

Data made available to all market participants: On a half-hourly basis: Forecast energy prices for the next day Regional reference prices On a two-hourly basis: Pre-despatch schedule prices up to the end of the following day Data not made available to market participants: Bid/offer data Scheduled generation and demand by node

8.23 An electronic market information system provides forecast, provisional and final despatch data on generation output, demand and prices at a reference node on each island, as shown in Table 9. Reference prices are also released to the public via an Internet site. However, information on bids and offers, and actual nodal scheduled generation and demand, are not released. A further electronic information system provides access to current and historic data on reservoir levels and inflows for the main hydro systems.

Argentina

8.24 In Argentina, scheduling is based on marginal fuel costs and plant data, such as efficiency, submitted by generators every six months. Generators have some flexibility in the level of the fuel costs submitted, but do not enter bids. Scheduling of plant takes account of start-up costs. Nodal prices are calculated, to reflect transmission losses and take account of transmission constraints.

8.25 The complexity of the scheduling mechanism is, to some extent, offset by the fact that bids are fixed for six months at a time. Over the course of each six month period, it becomes increasingly easy for participants to understand how prices will react to changes in demand.

8.26 The provision of information in Argentina is extensive. Market participants have access to data on fuel costs, forecast schedules, and daily despatch and prices.

California

8.27 Participants in the voluntary Power Exchange will submit simple price/volume curves for their portfolio for each hour at the day-ahead stage. However, it is intended for the bidding process to be iterative and subject to a set of activity rules. Nonetheless, prices will be determined simply by the intersection of the supply and demand curves at the end of the final iteration.

8.28 The hourly balancing market for deviations from the day-ahead schedule will also rely on simple price and volume bids. In this market, bids will be plant specific.

8.29 It is still unknown what information will be made available to participants and interested parties by the Power Exchange.

9. SUMMARY OF DIFFERENCES

9.1 The previous chapters have described in some detail the trading arrangements of six systems: Scandinavia (Nord Pool), VicPool and the NEM in Australia, New Zealand, Argentina and California. These have been compared with the arrangements in place in England and Wales. In this chapter, we seek to highlight the main differences between the arrangements whilst recognising that detailed differences can often be as important as broad distinctions.

Governance

9.2 In Scandinavia, New Zealand and California, the governance arrangements have been specifically designed for maximum transparency and accountability. The roles of market operator and system operator have been separated. In New Zealand and California, the power exchange has been formed as a not-for-profit company. The boards of the system operator and power exchange in California include representatives of all interested parties, including customers.

9.3 The roles of system operator and market operator are combined in the Australian markets and Argentina, as they are in England and Wales. However, except in England and Wales, these companies do not own the transmission network. The Australian markets have not-for-profit power exchanges and the board of the Australian NEM power exchange is currently composed predominantly of members who are not directly involved in the electricity industry. Similarly, four of the nine members of the board of VicPool are not connected with the industry. In Argentina, the majority of board members are industry participants.

9.4 The Electricity Pool in England and Wales is composed exclusively of generators and suppliers as a result of their signature of a private contract, the Pooling and Settlement Agreement although third parties, including NGC, OFFER and consumers may sit on Pool committees in a non-voting capacity.

Trading inside the Pool

9.5 All the markets considered use a marginal pricing approach in which the clearing price is set by the last accepted offer in a settlement period.

Energy payments

9.6 New Zealand and Victoria have adopted an ex post pricing approach. The others have adopted an ex-ante approach. The NEM1 and NEM in Australia are moving towards essentially real time pricing of electricity. The other ex ante markets all incorporate a day-ahead pricing mechanism. New Zealand and Victoria have daily ex post markets.

9.7 In systems where prices are set on an ex ante basis, there is a requirement for a mechanism to deal with deviations from the ex ante schedule. These can arise from demand forecasting errors and plant failures (in England and Wales, transmission constraints also contribute to the deviations). Such deviations can either be settled directly by instructions from the system operator or through on the day ex post balancing markets.

9.8 England and Wales, the NEM in Australia and Argentina allow the system operator to balance the market. Smeared charges are then used to recompense the system operator for the costs of settling the deviations. The Scandinavian and Californian trading arrangements, on the other hand, incorporate balancing markets.

Bidding format

9.9 Generators submit simple price and volume bids in Scandinavia, New Zealand, Victoria, the NEM and California. The technical limitations of plant are not explicitly taken into account in these markets, instead the generators have to internalise them in their bids. Plant limitations are included in the scheduling process in Argentina and England and Wales. These markets also explicitly allow generators to recover their start-up costs and, in England and Wales, their no-load costs.

9.10 In systems with ex ante pricing, the issue of the degree of commitment implied by a bid also arises (with ex post pricing, it is irrelevant since prices are determined by the actual, rather than forecast, performance of plant). In California and Scandinavia, accepted bids constitute a financial commitment for generators and they are cashed-out for any deviations from their bids. No such commitment is implied by the acceptance of bids in Australia, Argentina or England and Wales and generators are free to alter the availabilities of their plant after the price-setting schedule has been completed.

Capacity payments

9.11 Only England and Wales and Argentina have a separate price for capacity. Norway and Victoria have, at various times, contemplated introducing capacity prices but no mechanism has been implemented.

9.12 However, Victoria and NEM have provisions for the market operator to contract for reserve if this is considered necessary for security reasons.

Transmission constraints and losses

9.13 The costs of transmission constraints and losses can either be incorporated in energy prices or priced separately. Regional pricing of transmission constraints is not

incorporated in systems of England and Wales, Victoria and Sweden but are incorporated in the remaining systems. In Victoria, transmission constraints are so infrequent that no special provision was made for their treatment in the trading arrangements.

9.14 Nodal pricing, as adopted in New Zealand and Argentina, fully reflects the impact of constraints on the marginal price of power at each injection and offtake point on the system. Zonal pricing, implemented in Norway, Australia and California, involves a greater degree of averaging than nodal pricing but still incorporates locational pricing signals.

9.15 In England and Wales, the costs of constraints are averaged across the entire system and generators are recompensed on the basis of their bids. A similar approach is adopted for within zone constraints in systems with zonal pricing.

9.16 There has been little consensus in the treatment of losses on the different systems. New Zealand and Argentina have adopted dynamic nodal pricing of marginal losses. Nodal pricing of losses has also been implemented for customers in Victoria and generators in California. However, in Victoria losses are not calculated dynamically but on a seasonal/time of day basis whilst in California average rather than marginal losses will be used. In Norway and the NEM, pricing is on the basis of marginal zonal losses but whereas Norway, like Victoria, sets prices periodically, the NEM involves dynamic pricing. England and Wales currently charges a single uniform price on the basis of average losses.

9.17 Since marginal losses are always higher than average losses, a surplus of revenues over costs is accumulated in systems that charge on a marginal loss basis. In all these systems, the surplus is used to reduce transmission charges.

Demand side participation

9.18 So far, demand side participation has been relatively limited in all the markets although, in some cases, the trading arrangements make provisions for extensive demand side involvement.

9.19 In Scandinavia and California, demand is bid into the day-ahead market and a demand curve is built up against which generation is matched. Demand side bidding is allowed in England and Wales and the Australian markets but, instead of building up a demand curve, load reduction bids are treated as “negative” generation.

9.20 In markets where prices are set ex post (the main market in New Zealand, and the balancing markets in Scandinavia and California), customers can respond to the published forecasts of prices. In so doing, they influence the final prices that are set. Load reduction bids are also allowed in the balancing markets.

Trading outside the Pool

9.21 Scandinavia, California and New Zealand all allow full trading outside the pool through bilateral physical contracts. Argentina allows bilateral contracts but these are settled through the pool from the output scheduled for generators. Australia and England and Wales do not allow physical bilateral contracts.

9.22 Only in Scandinavia has trading outside the pool developed to any significant extent. In California, the three main utilities will be obliged to trade all their electricity through the pool for the first four years, so trading outside the pool is unlikely to be substantial initially.

APPENDIX 1 – TIMETABLE

February	Publication of OFFER background papers on (a) present electricity trading arrangements in England and Wales and related issues and (b) electricity trading arrangements in other countries
23 February	Explanatory workshop on issues raised in the background papers
March	Publication of the OFFER working papers on trading arrangements both inside and outside the Pool
30 March	Explanatory workshop on the trading arrangements models
Early April	Publication of third party working papers on electricity trading arrangements
14 April	Explanatory workshop to discuss the third party working papers
15 & 16 April	Two day seminar to consider possible models for electricity trading arrangements both within and outside the Pool
Early June	Publication of interim conclusions
15 & 16 June	Seminar on interim conclusions
July	Publication of final report to Minister on conclusions and recommendations