H KEMA – Information Paper on Supplementary Market Mechanisms to Deliver Security and Reliability

Information Paper on Supplementary Market Mechanisms to Deliver Security and Reliability

Final

15 September 2009

Executive Summary

The Australian Energy Market Commission (AEMC) have commissioned KEMA to provide them with an information paper on a number of alternative market design elements applied in different electricity markets worldwide as a supplement to the energy market. The purpose is to inform AEMC of the key features of a number of different models, examining the pros and cons of each feature with particular reference to the extent to which the models deliver reliability and security of supply. To reinforce the analysis of the advantages and disadvantages of each model and the ways in which all or elements of the models can be combined within a set of market arrangements, this report also considers the practical implementation of the models in six different international markets.

We emphasise that the alternative market models discussed in this paper represent an addition, or supplement, to the underlying fundamental energy market model, i.e. the choice between pool markets with centralised scheduling or bilateral contracts markets with decentralised scheduling. Consequently, the different mechanisms discussed in this report should not be regarded as an alternative to these basic market models. Nevertheless, it is worth noting that most of the approaches presented in this report represent a deviation from the principle of an "energy-only" market as the additional design elements focus on capacity and reliability.

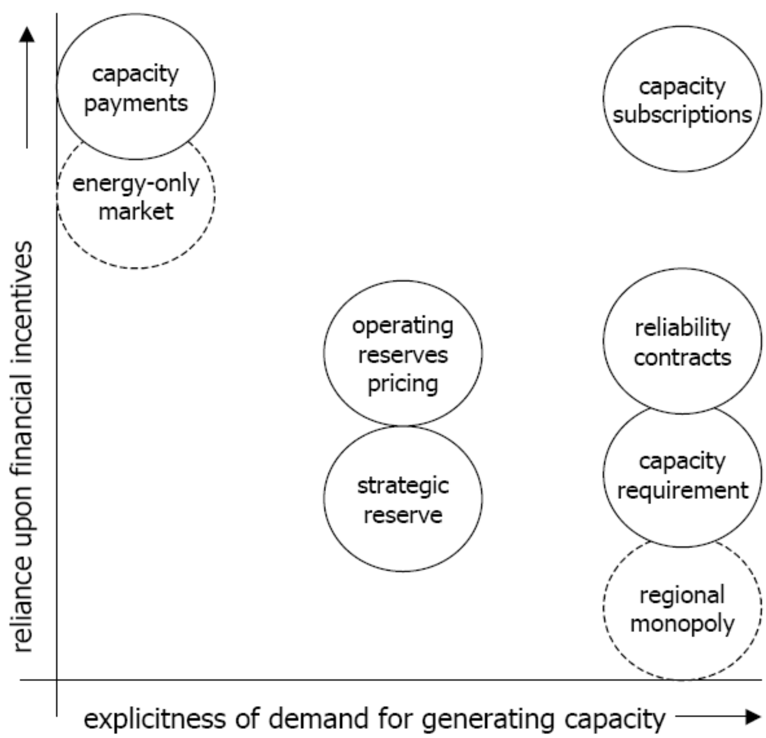
Four different groups of market models have been examined. These can be summarised as follows:

1. **Quantity-based capacity mechanisms**, including the following sub-models:
    a. Capacity markets (Capacity Obligations);
    b. Reliability options;
    c. Peak load reserves;
    d. Operating reserve model;
2. **Price-based capacity mechanisms (capacity payments)**;
3. **Establishment of long-term bilateral contracts**; and
4. **Demand-side measures**, including
    a. Short-term pricing; and
    b. Provision of operating reserves by interruptible customers.

The examination focussed on the quantity based and price based capacity mechanisms as these are the main techniques that have been utilised worldwide to provide reliability and security in many of the markets studied.

Although these models universally aim at ensuring reliability, they apply different principles and instruments to reach this goal. This is illustrated in the figure below which compares the different models with respect to the explicit specification of the need for a given level of capacity on the one side, and the reliance on financial incentives on the other side.

Overview of Market Models Intended to Ensure Reliability



Source: De Vries, L.J. Securing the public interest in electricity generation markets, The myths of the invisible hand and the copper plate. Ph.D. dissertation. Delft University of Technology. 2004

Besides a description of the principles and rationale of each model, each model has been assessed in delivering investment, reliability and security of supply and promoting economic efficiency. The table below summarises the results of the analysis of the market models.

Summary of Alternative Market Design Features Aimed at Enhancing Reliability and Security of Supply

Model	Key Features	Key Issues
Capacity Market (traditional)	Volume obligations placed on retailers, to be met by purchases of certified volumes from generation	Not clear that security of supply at system peak is enhanced. Some volatility in energy markets may be ameliorated. High transaction and administrative costs.
Reliability Options	(Financial) Call options for forward energy	Strong incentives to make capacity available at time of peak load. Effective hedge against price spikes. High transaction and administrative costs.
Peak Load Reserves	Control and operation of selected peaking plant by the System Operator	Security of supply may be enhanced in the shorter term, but long-term efficiency may be compromised. Concerns about System Operator competing in market. Limited costs.
Operating Reserves Pricing	Market-based procurement and pricing of operating reserves	Focus on security rather than adequacy. May provide additional income to peaking plants. May promote short- and long-term efficiency. Limited costs.
Capacity Payments	Capacity pricing alongside energy pricing, based either on costs or value of such capacity	Not clear that security of supply at system peak is enhanced. No incentives for efficiency. High costs.
Long-term Bilateral Contracts	Use of long-term bilateral contracts	Provides for efficient hedge against uncertainty but unlikely to function on a voluntary basis. Promotion of short-term efficiency. Barriers to entry impair long-term efficiency
Demand-Side Short-Term Pricing	Demand response to (tariff) pricing	Supports reliability / adequacy but unlikely to be sufficient on its own. Facilitates efficient outcomes for scheduling and dispatch. May reduce costs
Interruptible Load	Demand response to instruction, or automatically, as a form of Operating Reserve	Supports security but unlikely to be sufficient on its own. Facilitates efficiency of reserve provision. May reduce costs

To provide for a more structured view, the table below provides a simplified evaluation of the models, enabling the following observations to be made:

- Only the first two or three of the models are likely to directly ensure that the desired reserve margins will be met. However, all of these first three models also have some significant disadvantages, including the creation of barriers to entry (1 – 3), the lack of incentives for maximising output and the risk of manipulation (1), high complexity and costs (1, 2) or concerns related to the long-term efficiency of the mechanism (3). In a direct comparison, the concept of traditional capacity markets furthermore appears as being generally inferior to reliability options.

- Price-based mechanisms (5) may not succeed in assuring reliability. Moreover, capacity payments are unlikely to result in an economically-efficient outcome.
- Whilst short-term bilateral contracts have obvious advantages, we are not convinced about the case for voluntary long-term agreements (6) for peaking plants. Conversely, any mandatory requirements would likely impair long-term efficiency and create serious barriers to entry.
- Demand-side measures (7, 8) generally increase economic efficiency, are fully compatible with the basic market design and come at limited costs. However, they are unlikely to ensure reliability on their own.
- Market-based pricing of operating reserves seems likely to show a good performance in almost all of the criteria considered. However, it focuses on security rather than adequacy such that it is not clear that reliability will be enhanced.

Simplified Assessment of Alternative Market Models

Criteria for Evaluation	Quantity-based mechanisms						Demand-side measures	
	Capacity Market	Reliability Options	Peak load Reserves	Operating Reserves pricing	Capacity Payments	Long-term Bilateral Contracts	Short-term pricing	Provision of operating reserves
	1	2	3	4	5	6	7	8
Reliability and security of supply								
Ensure reserve margin	+	++	(+)	(+)	0	-	(+)	(+)
Maximise output during scarcity	0	++	++	+	0	++	+	+
Economic efficiency								
Long-term	(+)	(+)	(+)	+	-	-	+	(+)
Short-term	0	++	+	+	-	++	+	+
Costs	--	--	+	+	--	?	++	++
Compatibility with market design	+/-[(a)]	+/-[(a)]	-	+	+/-[(a)]	--	++	++
Barriers to entry	-	-	--	+	+	--	+	+
Feasibility (complexity)	--	--	0	+	0	+	+	+

Evaluation: ++ - Very good; + - Good; (+) – Generally good, with some reservations; 0 – Mediocre; - - poor; -- - very poor; ? - questionable

[(a)] *– Markets with centralised / decentralised scheduling*

To provide examples of the application of each of these alternative forms of energy market design KEMA have also reviewed their application in the following markets:

1) PJM,
2) New York,
3) Western Australia,
4) Great Britain (BETTA),
5) Irish SEM, and
6) Nordic market (Nord Pool).

The table below summarises the mechanisms to provide reliability and security of supply in each considered market alongside the NEM as a comparator.

	Models Applied	**Evidence to date**
NEM	Energy only market with restrictions on maximum prices set high to allow achievement of reliability standards. Financial markets allow for longer term contracting and system operator can enter into reserve contracts in specific circumstances. Market has been designed to include Demand side participation.	Reliability standards assessed over the longer term have been met in all regions. There has in recent years been increasing price volatility and prices have increased from historic lows. This has seen increased amounts of generation being proposed and commissioned.
PJM	Capacity market includes rules for calculating generating margin requirement with encouragement for demand side participation	The initial capacity market in PJM suffered some problems. However, a new capacity auction was implemented in 2004. This has seen greater volumes of capacity procured including significant demand response.
NYISO	Capacity market established with rules for calculating the required generation requirement and for determining the level of unforced capacity that each generator contributes.	Initial implementation of the capacity market saw large price variations even when there were only small variations from the capacity target, although subsequent changes stabilised the price and revenue streams. However, there is concern on market power in constrained zones and that the capacity

	Models Applied	Evidence to date
		market has not stimulated new resources as the capacity margin is shrinking.
BETTA	Left to the market with information provided to stimulate investment. In addition introduction of demand participation and active market procurement of reserves (with incentives on the procurer to reduce costs)	Heavy consolidation and vertical integration to-date. No significant events so far. Large queue of new generation set to come on stream in next 10 years in response to emissions targets, EU legislation, Government fuel diversity policy and market conditions.
SEM	A number of mechanisms exist principally capacity payment schemes but also demand side management scheme and ancillary services that help with security of supply.	Relatively recent market opening means limited evidence yet on the success of the capacity mechanism. Demand side management programmes have been run with some success to improve supply security.
Western Australia	The Principal scheme in Western Australia is a capacity market. In addition there is the provision of operating reserve and the ability for the demand side to participate in the Capacity Mechanism.	The capacity mechanism has been successful in procuring excess levels of capacity in each of the last 4 years with strong investment across all fuel types, although there is some concern on the level of investment of plant with dual fuel capability. There is now sufficient capacity entering the SWIS to meet projected demand until the 2014/15 period.
Nordic Countries	1) Peak load arrangements in Sweden and Finland; 2) Forward contracting of operating reserves; 3) Specific arrangements to incentivise demand-side provision of operating reserves (in Norway); and 4) Partial use of short-term pricing for consumers	Although the Nordic electricity market is generally considered a showcase of successful liberalisation, the ‘temporary’ introduction of peak load arrangements in Sweden and Finland is a clear sign of concerns about long-term reliability in a hydro-dominated system. Whilst demand-side participation has been highly successful especially in Norway, it has to be seen in the light of the specific

	Models Applied	Evidence to date
		consumption structure, with a high proportion of energy-intensive industry and the wide-spread use of electric heating; consequently, the potential in the other Nordic countries is being regarded as much lower than in Norway

On the basis of the analysis of the different possible market models and the evidence to date of their implementation in the six international markets examined, KEMA have drawn the following key observations and conclusions which may be of particular relevance to the AEMC and the prevailing market context in Australia;

1) None of the alternative market models discussed seems to be perfect in a sense that it fully satisfies all of the defined criteria.

2) In particular, only very few models are likely to provide a reasonable ‘guarantee’ of actually being able to assure reliability. This advantage however comes at the expense of a possible deterioration of long-term efficiency and/or significant costs and complexity of the mechanism.

3) A comparison of international markets, including those specifically considered in this report, shows that the mechanisms focusing on the promotion of generation adequacy, i.e. some form of capacity obligations or capacity payments, are more commonly found in centralised pools than in bilateral markets. Amongst others, this is related to the issue of measuring the availability of generation to the wholesale market, which is a crucial precondition for many of the market models considered in this report.

4) Some of the markets now have many years experience of continuing to operate successfully in providing security and reliability of supply. Others have exhibited periods of high prices, but this may be due to input costs and availability (e.g. high fuel prices, shortages of water) as much as the inability of the market to provide sufficient generation capacity. Most importantly, there does not seem to be a clear relation between the application of specific capacity mechanisms and improved reliability, and vice versa.

5) Although demand-side measures can only support reliability, at least some potential may possibly be made available at limited costs. If these measures are limited to specific large customers, then they are less difficult to implement than a full market design and can improve efficiency without

presenting any additional barriers to entry for generators. However, the potential for demand-side measures strongly depends on the specific consumption structure of a given market, whilst the general application of demand-side measures to all consumers may result in significant costs and complexity.

6) Similarly, the market-based procurement/deployment and pricing of operating reserves generally shows a positive performance against all of the criteria defined above. The main disadvantage of this model is related to the fact that it provides only an indirect way of promoting reliability. However, the proposal of an ‘operating reserves pricing’ model with a (partial) purchase of excess operating reserves may offer an improved performance in this respect.

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Revision History

Rev.	Date	Description	Author	Checker	Approver
0.1	12 May 09	Proposed Report Structure	MW	JD	JP
0.2	12 May 09	Addition of Market Models	CH		
0.3	05 June 09	Draft text for section 2	NC, JoP, JeP	CH	
0.4	9 June 09	Enhancements to Countries	JeP, JoP, DL	JP	
1.0	12 June 09	Completion of full draft	JoP, DL, CH	JP	CH
1.1	25 June 09	Final QA and update for comments	JoP, DL, CH	LP	DL
1.2	19 August	Updated to include new section	CH	DL	DL
1.3	15 Sept 09	Issued as Final Report	DL	DL	DL

1. Introduction

1.1 Background

The Australia Energy Market Commission (AEMC) have commissioned KEMA to provide them with an information paper on a number of market design features applied in different energy markets worldwide. The purpose is to inform AEMC of the pros and cons of each feature with particular reference to the extent to which the models deliver reliability and security of supply. To reinforce the analysis of the advantages and disadvantages of each model and the ways in which all or elements of the models can be combined within a set of market arrangements, this report also considers the practical implementation issues associated with these models in other international markets.

1.2 Structure of this Report

This report has been structured into the following sections:

- Section 2 provides an overview of reliability in an energy only market and the price volatility that relying solely on this mechanism may generate. It provides a brief overview of the NEM market as an example of an energy only design with some controls and supplementary measures that prevent the full extremes of a pure energy only market occurring.

- Section 3 examines four types of supplementary market design models, two of which can be further subdivided to differentiate between their specific characteristics such that a total of eight different models are described. In each case an overview of the model, a detailed description of the model features, a qualitative assessment of the strengths and weaknesses of the model and a description of experiences of the model to-date in an operational environment is provided;

- Section 4 provides details of six different international markets. Each market assessment starts by establishing the context for the market and provides a description of the market arrangements, the features of the arrangements which seek to encourage reliability and security of supply and a qualitative examination of their success and/or short-comings to-date; and

- Section 5 provides a number of key observations which KEMA assess to be of particular relevance to the AEMC and the prevailing market context in Australia.

2. Energy Only Markets and the NEM

2.1 Background

One option for reliability and security in a market is to simply allow electricity prices to move to reflect any shortage of supply and demand and provide the appropriate signals for market entry and exit. Under this scenario there would be no additional payments for capacity or availability, merely the opportunity for high prices at times of tight supply and demand fundamentals. In essence this approach is similar to many other commodity markets e.g. oil and gas, but does create risks of undersupply and high levels of price volatility. There are also characteristics of electricity such as difficulties with storage, lack of substitutes, the time required for new generation entry and the social desire for wide affordable access to the product that have led to some question whether additional incentives are needed in the market to ensure reliability.

This section outlines the theory behind energy only payments and some of the practical difficulties that can occur which may require the adoption of additional mechanisms considered later in this report. It then provides a brief synopsis of the NEM market as an example of an energy only market with some deviations, either to encourage more capacity or to provide protection for customers against pure market pricing.

2.2 Reliability in an Energy-Only Market

The liberalisation of electricity markets has been based on the objective of introducing competition between buyers and sellers of electricity. According to standard economic theory, competition in an open and competitive market should result in an optimal, i.e. economically efficient outcome, with prices being determined by the equilibrium between supply and demand. Similar to any other market, this equilibrium will be found where prices are equal to the marginal costs of production.

Consequently, the design of every liberalised electricity market in the world is based on two fundamental principles, i.e. enabling free competition and the spot market pricing of electricity. In many countries, including some of the examples presented in section 4 below, this basic electricity market design has been supplemented by explicit additional mechanisms, which are specifically aimed at ensuring reliability. Conversely, other markets, including most of the European countries, rely on the principle of so-called **energy-only markets** where the price of electricity represents the driver for new investments into capacity.

It has been shown[1] that, under ideal circumstances, perfect competition in an energy-only market can provide efficient outcomes both in the short and in the long term. According to this school of thought, reliability in an energy-only market will be ensured by prices increasing in response to declining reserve margins, which in turn will incentivise investments into new generation capacity. According to economic theory, new capacity will be added when market prices are equal to the long run marginal costs (LRMC) of generation, whereas prices in the spot market will normally be equal to short run marginal costs (SRMC). Given that the short run marginal costs of electricity tend to be significantly lower than LRMC, reliability in an energy-only market therefore requires that spot market prices are allowed to sometimes move up to extremely high levels. The theory of energy-only markets is therefore sometimes also referred to as price-spike approach as it is inherently tied to the acceptance of price spikes and requires that prices in the spot market are not constrained by any price caps.

One fundamental precondition for the functioning of an energy-only market is a sufficient level of price elasticity such that the supply and demand curves always intersect. In practice, however, the short-term price-elasticity of electricity demand has generally been observed to be extremely low (unless in case of extreme price levels). Conversely, the supply of electricity becomes perfectly price-inelastic when the level of available capacity has been reached. In combination with the impossibility of storing electricity in a commercially viable way[2] and the significant time lag of investments into new generation capacity, it is often argued that an energy-only market may fail to find an equilibrium between supply and demand in a situation with an acute shortage of capacity. Besides the potential inability to clear the market, this may also create unlimited market power for generators, thereby undermining the scope for competition and an efficient outcome of the market.

The interaction of these effects may result in a large and prolonged boom-and-bust price cycle and extreme price volatility. Given the importance of power supply to a modern society, any corresponding supply interruptions bear the risk of causing excessive costs to the overall economy, which may not be adequately reflected in the spot price for electricity. Furthermore, the nature of reliability as a public good implies that it is hardly possible to have different customers (or customer groups) contracting individually for higher levels of reliability. Finally, it is important to take into account the common perception of electricity being an essential good. Supply interruptions and/or extreme price spikes may therefore be politically unacceptable, creating a significant risk of political intervention and undermining the scope for sufficiently high spot prices.

[1] Caramanis, M.C. (1982) Investment decisions and long-term planning under electricity spot pricing, IEEE Transactions on Power Apparatus and Systems 101 (12): 4640-4648.
Caramanis, M.C., R.E. Bohn and F.C. Schweppe (1982) Optimal Spot Pricing: Practice and Theory, IEEE Transactions on Power Apparatus and Systems PAS-101 (9): 3234-3245.

[2] Except for limited storage potential in existing pump storage plants

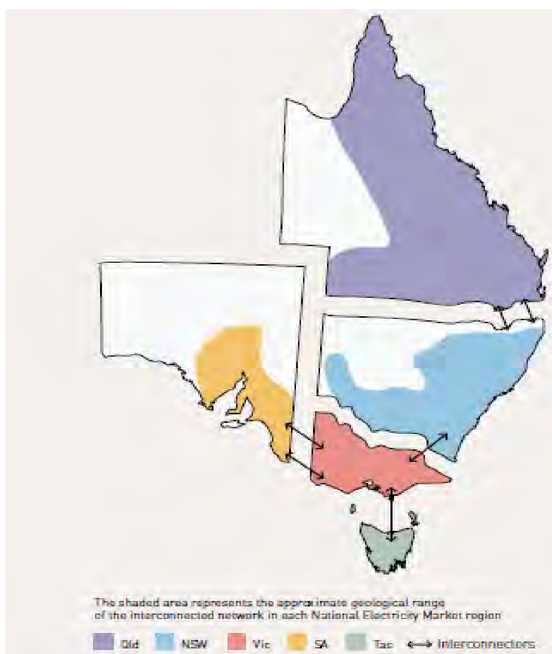
Whilst economic theory suggests that energy-only markets may ensure reliability by providing sufficient incentives to invest in capacity, it requires a delicate balance between investment and expected returns, which may be easily upset by a number of factors. It is therefore often argued that pure spot pricing of electricity is unlikely to function such that a second-best solution is required. In practice, virtually all electricity markets in the world, including the NEM, have therefore been supplemented by one or more additional features or mechanisms, which effectively create a deviation from the theory of an energy-only market, but aim at either preventing an excessive exercise of market power and/or providing additional incentives for reliability.

2.3 Experience in the NEM

2.3.1 Market Context

The NEM market covers the entire region from Queensland to South Australia including NSW, Victoria, Tasmania and the Australian Capital Territory. An overview of the network regions is shown in the diagram below

Figure 1NEM Market Regions (AER 2008 State of the Energy Market)



The NEM generators and retailers are a mixture of state owned and private sector organisations. There is full retail competition in all regions of the NEM market (except Tasmania), which has been gradually introduced over the last 10 years. Around 2/3rds of generation capacity is either Government owned or controlled.

Generation in the NEM comes from a mixture of sources with around 190 large generators. This capacity is dominated by coal fired station with 49% from black coal and 17% from brown coal. Other main sources include hydro (17%), Gas (10%) and wind with 1%. Significant regional difference exists with Queensland and NSW mainly supplied by black coal, Victoria heavily reliant on brown coal and Tasmania having high level of hydro capacity. South Australia stands out as having a high level of wind generation capacity (16%). These plants delivered a total energy demand for the NEM region in 2008 of 208 TWh

2.3.2 Overall Market Design

The NEM market is a gross pool market, which is operated by the Australian Energy Market Operator. All significant sales of electricity need to occur through this mechanism, although financial markets do exist that are not controlled by the AEMO.

Generators that are centrally dispatched need to submit 5 minute bids for generation. These bids are stacked in ascending price order for each five minute dispatch period. Generators are then dispatched using the AEMO's Dispatch Engine which co-optimises energy and Frequency Control Ancillary Services to minimise costs. Any dispatch takes account of technical factors such as generator ramp rates and network congestion as well as prices. A spot price is then established for each half hour which is the average of these 5 minute dispatch prices and this price is paid to all generators regardless of their offer into the Pool.

The market has been designed to allow demand side participation directly in the market (as well as indirectly through contracts with Retailers). With direct participation the customers will offer to reduce demand (withdraw from the market) once the spot price reaches a particular threshold and resume operation once the price falls back to the level of their bids. This allows the customers to avoid the very high peak prices.

Whilst the NEM is a single market there is a need to calculate a separate spot price for each of the 5 regions. This takes into account physical losses and transmission constraints that can isolate certain regions of the market. Where there is congestion in a particular region this can lead to price spikes, which can be significant with average annual NEM prices in 2007/08 ranging between $31MWh in the Snowy region to $101MWh in South Australia.[3]

The NEM is an energy only market and no additional payments are made for capacity. Theoretically this would suggest that there should be no price cap to ensure that infrequently used generators will enter/remain in the market. However, there is also a need to mitigate customer risk and this had been

[3] AER State of the Energy Market 2008

balanced by the use of a relatively high price cap. This is discussed further below in the reliability measures.

Financial Markets

Alongside the NEM market there are financial electricity markets. These provide a mechanism for both generators and retailers to hedge the risks they face in the NEM. The financial markets also provide price signals for energy infrastructure investors and allow income streams to be locked in for a period of time. There are two distinct financial markets for electricity products in the NEM which are:

- Over the counter (OTC) markets for bilateral trades between counterparties. These are confidential agreements often arranged with the assistance of a broker with financial intermediaries offering some additional depth.

- Exchange traded market of the Sydney Futures Exchange (SFE) which has electricity futures products. In this case licensed brokers buy and sell contracts to market participants that include traders, generators and retailers. These products are highly standardised and are settled through a centralised clearing house. These contracts are publicly reported, which leads to increased market transparency and price discovery than the OTC market would deliver.

These financial markets are responsible for large volumes of energy which represent a multiple of the NEM demand. This is shown in the table below.

Table 1 Volumes traded in the OTC and SFE Markets (AER State of the Energy Market 2008)

Year	OTC (TWh)	OTC (% of NEM Demand)	SFE (TWh)	SFE (% of NEM Demand)	Total (% of NEM Demand)
2005-06	117	92	55	28	120
2006-07	337	172	243	124	296
2007-08	304	156	241	123	279

2.3.3 Specific Mechanisms aimed at Supporting Reliability and Security

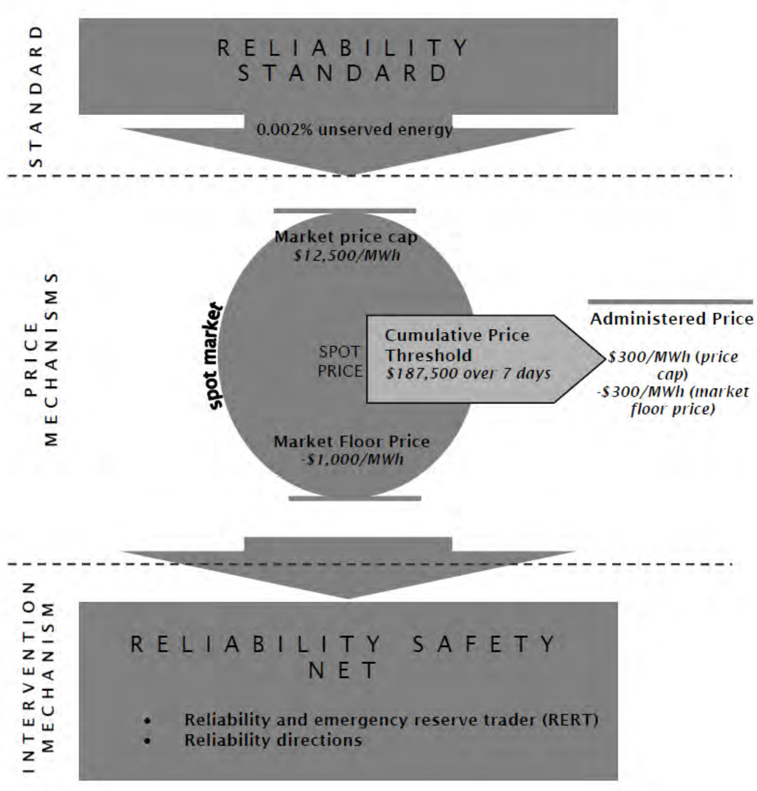
2.3.3.1 Overview

The NEM has a reliability standard that sets the level of Unserved Energy (USE) at 0.002% of annual energy consumption for each region. To deliver this standard the AEMO determines the necessary spare capacity for each region that needs to be available either from generation or transmission interconnections. These minimum levels should provide a buffer against unexpected demands and generation failures.

In order to achieve this reliability standard there are three administered prices mechanisms that need to be established. There is a Reliability Panel that is required every two years to consider these settings and balance the need for certainty for consumers and investors alongside the need for appropriate and timely consideration to overall NEM reliability Performance. It needs to report against the reliability standards and minimum reserve levels set by the AEMO.

In addition to the administered price mechanisms there are also intervention mechanisms that provide a reliability safety net. An overview of these options is shown in the diagram below along with a short description in the following section.

Figure 2NEM Reliability Standards that apply from 1 July 2010[4]



2.3.3.2 Price Mechanism for Reliability

There are three price mechanisms that can be used to balance reliability with customer protection. These are:

[4] Taken from AEMC Issues Paper – Reliability Standards and Settings Review

- Market price cap (previously known as VOLL)
- Market floor price
- Cumulative price threshold

Market Price Cap (MPC)

The level of this parameter is viewed as crucial in providing the right balance between giving signals for supply and demand investment and usage.   If the MPC is too high then customers (and generators who have taken positions they can't deliver) will be exposed to large financial risks. If the level of the MPC is set too low then insufficient new generation may emerge resulting in a risk of higher levels of USE and a failure to meet the Reliability Standard.

Extensive modelling in the Comprehensive Reliability Review showed that unsurprisingly as the level of MPC increased that the level of USE fell. This modelling also demonstrated that the previous level of the MPC ($10,000 MWh) would result in a breach of the reliability standard between 2010 and 2014.   The Reliability Panel therefore determined that it was prudent to raise the level of the MPC to $12,500 MWh from 1 July 2010. This will encourage Retailers to engage in greater levels of contracting and also encourage new generation and customers to participate in demand side measures.

Market Floor Price

The market floor prices should also provide investment signals in terms of risks for new generation. However, the Panel's modelling in the Comprehensive Reliability Review stated that the level of the market floor price appeared to have little or no effect on the amount of USE.   This is currently set at minus $1,000 MWh.

Cumulative Price Threshold (CPT)

The CPT is a mechanism designed to limits participants price exposure to continued high prices. It has been specifically designed not to hinder investment or the remuneration of occasionally utilised capacity as it is set at a level that should be very infrequently reached.   Indeed since the start of the NEM this has only been applied on one occasion.

The CPT works by applying an Administered Price Cap if the sum of the half hourly wholesale market spot prices over a rolling seven day period exceeds this threshold. The CPT is being raised to $187,500 at 1 July 2010. This has been increased from the previous level of $150k recognising that the higher MPC would otherwise lead to more frequent breaches of the CPT.   Once this threshold is reached an Administered Price Cap is applied, which is set at +/- $300/MWh for all regions of the NEM.

2.3.3.3 Reliability Safety Net

The reliability safety net includes the reliability and emergency reserve trader (RERT) mechanism and reliability directions that can be used by AEMO to reduce USE that accrues.

Reliability Emergency Reserve Trader (RERT)

Whilst the NEM is an energy only market there is an option for the AEMO to use the RERT mechanism to procure additional reserve generation or demand side response. This is required to meet minimum reserve levels at times of peak demand and is designed to be a short term emergency reliability mechanism that is used only when the market has failed to ensure reliable supply.

The RERT procedure requires the AEMO to seek assurances that any offered reserve will not be offered in the market outside of the reserve contract. This means that the reserve must not be offered in the wholesale market or for provision of ancillary services. It allows for reserve generation (load) to be contracted up to 9 months ahead, although it cannot be used for short term shortfalls as there is competitive tendering and contract negotiation rules. Payments for RERT are made for availability and it does not constrain the price at which additional capacity can be offered.

The Reliability and Emergency Reserve Trader Mechanism was introduced as a facility available to the AEMO in 2008. However, this mechanism is only enabled if the supply-demand balance indicates that spare capacity in a particular regions falls below target levels. At this point AEMO will conduct additional studies to determine if reserve capacity needs to be procured to maintain the established level of electricity supply. The 2008 Statement of Opportunities indicated that spare capacity could fall below the target levels in Victoria and South Australia combined in 2008/09. However, additional research by AEMO indicated that this should not impact the reliability standards in the 2 states and therefore the AEMO did not foresee a requirement for market intervention.

The RERT is a sunset clause that is due to expire on the 30th June 2012.

Reliability Directions

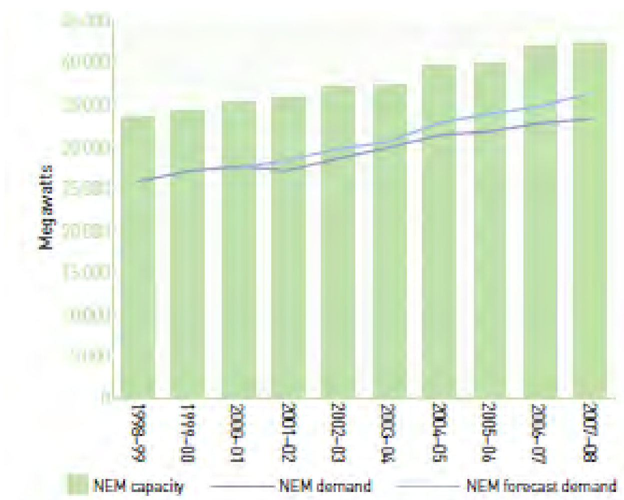
The AEMO does have powers as part of the National Electricity Rules to require registered participants to take action to maintain or re-establish the power system to a secure operating state. These actions can include shutting down or varying operations, increasing or reducing active or reactive power and taking equipment in/out of service. In these circumstances the AEMO would need to expressly notify participant that this requirement is a direction. It should be noted that the order of dispatch have Plant subject to a direction at the bottom of the list with all other options utilised earlier.

Unlike the RERT there is no sunset clause with this provision. It is also not subject to the Reliability Panel's assessment of reliability settings.

2.3.4 Experiences to Date

The NEM has continued to see increased peak demand over the last ten years and capacity has increased in line with this increased demand with sufficient safety margin of capacity to maintain a reliable power system. This is shown in the diagram below. NEMMCO has twice contracted for but not had to dispatch reserve to ensure that the summer peak demand was met. This was in summer of 2004/05 and 2005/06 using the forerunner to the current RERT scheme.

Figure 3 NEM Peak Demand and Generation Capacity (Source AER 2008 State of the Market)[5]



There has been significant price volatility in the NEM market in recent years with an increasing number of prices above $5,000 MWh. This has partly been caused by high temperature and record demand in Victoria and South Australia with average prices also increasing from lows seen around 2002-2004. These price increases have seen significant plant proposed over the next few years.

The Reliability standard has been set at 0.002% since the start of the market in 1998 and historically the NEM has performed well against the standard, which is normally assessed over the longer term. There are a number of small breaches in some regions and if industrial action is included then South Australia and Victoria are outside the Reliability Standards. If industrial action and acts of god are excluded, as

[5] Forecast demands are taken 2 years earlier based on a 50% probability the forecast will be exceeded. The NEM capacity excludes wind and power stations not managed through central dispatch.

recommend by the Comprehensive Reliability Review, then all regions are well within Reliability Standards for the past 10 years.

The Cumulative Price Threshold has only been applied once since the NEM market began operations. This was in March 2008 in South Australia. This was driven by temperatures in Adelaide of up to 40.1 degrees and in Melbourne of 37.8 degrees. This meant that the administered price cap was applied such that spot market prices could not exceed $100 MWh at peak times and $50 MWh at off-peak times.[6]

[6] Note – This event occurred before the APC was raised to $300 MWh at all times.

3. Comparison of Alternative Market Models

3.1 Overview of Market Models and Criteria for Evaluation

This section provides a review of alternative forms of Market Models as applied in different electricity markets worldwide as a supplement to an energy-only market. It includes a comparison of these alternative Market Models, highlighting key features and attributes, key strengths and weaknesses; and their applicability and suitability within different market contexts. We emphasise that this comparison focuses on specific elements or mechanisms, which are specifically targeted at promoting reliability and security. Conversely, this report does not assess the basic market design models, i.e. the choice between pool-type markets with centralised scheduling as opposed to bilateral contracts markets with decentralised scheduling. The different mechanisms discussed in this report do not represent an alternative to these basic market models, but should be seen as an additional element within the overall market model. Nevertheless, it is worth noting that most of the approaches presented below do represent a deviation from the principle of an "energy-only" market as the additional design elements focus on capacity and reliability.

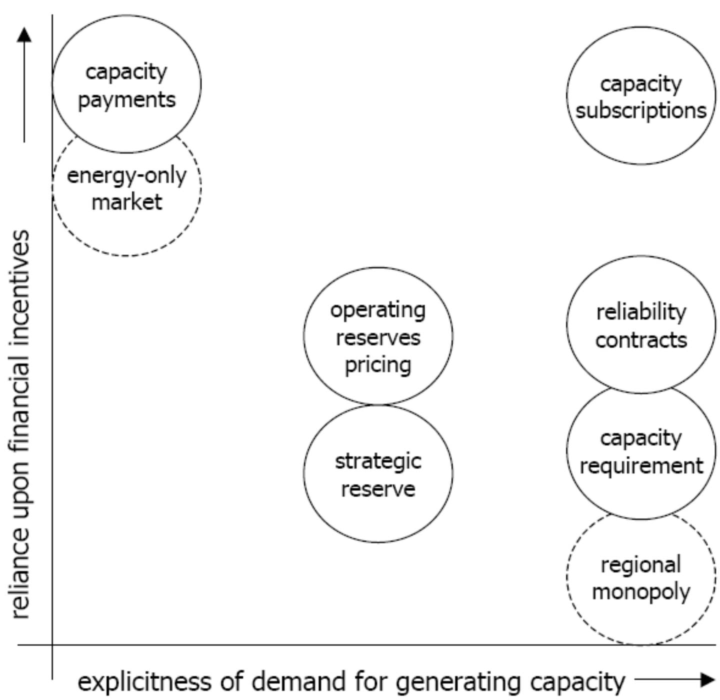
Overall, our analysis covers four different groups of market models, which can be summarised as follows:

1. **Quantity-based capacity mechanisms**, including the following sub-models:
    a. Capacity markets (Capacity Obligations);
    b. Reliability options;
    c. Peak load reserves;
    d. Operating reserve model;
2. **Price-based capacity mechanisms (capacity payments)**;
3. **Establishment of long-term bilateral contracts**
4. **Demand-side measures**, including
    a. Short-term pricing; and
    b. Provision of operating reserves by interruptible customers.

The principle focus of this section has been on the quantity based and price based capacity mechanisms. These are the main techniques that have been utilised worldwide in provide reliability and security in many of the markets studied. The other market models are included for completeness and are sometimes an additional feature that is provided to encourage security alongside the capacity mechanisms (i.e. the ability for the demand-side to receive capacity payments).

Although these models universally aim at ensuring reliability, they apply different principles and instruments to reach this goal. For illustration, Figure 4 compares the different models with respect to the explicit specification of the need for a given level of capacity, on the one side, and the reliance on financial incentives, on the other side. As suggested by the term "quantity-based mechanisms", the first group of models focuses primarily on reaching a certain level of capacity, whereas capacity payments represent a more indirect approach, whereby reliability shall be promoted solely through the use of financial incentives. Whilst the same is basically true for the use of long term bilateral energy contracts, the strength of the financial incentives may be less as there is no payment that reflects a direct reward for capacity. Demand-side measures finally cover a variety of supplementary measures, which aim at supporting the functioning of other mechanisms and therefore also show a larger variation with regards to the use of quantitative goals or financial incentives.

Figure 4: Overview of Market Models Intended to Ensure Reliability



Source: De Vries, L.J. Securing the public interest in electricity generation markets, The myths of the invisible hand and the copper plate. Ph.D. dissertation. Delft University of Technology. 2004

Besides a description of the principles and rationale of each model, the following sections also serve to assess the performance of each model in delivering investment, reliability and security of supply and promoting economic efficiency. To facilitate a structured comparison, this assessment is based on a set of four main criteria, which each combine a number of different aspects. These four main measures, which are further explained below, are:

1) Assuring reliability and security of supply;
2) Promoting economic efficiency;
3) Compatibility with other elements of market design; and
4) Feasibility and costs of implementation.

Assuring Reliability and Security of Supply

As already mentioned above, this report puts particular emphasis on design elements aimed at supporting reliability and security in liberalised electricity markets. As a first criterion, we therefore analyse to what extent each model can be expected to ensure that sufficient volumes of generation capacity are built and/or kept in operation.

In our analysis, we focus on the aspect of generation adequacy, although we also consider the impact on security (i.e. the capability of the system to cope with unexpected changes during real-time operations). Ensuring an adequate level of generation capacity requires potentially significant investments, which will only be made if investors expect to at least recover their fixed costs (including a reasonable rate of return). Given the long time horizon of investments into generation capacity, the level of (un)certainty on future payments is critical in this respect. The impact of each model in providing income certainty to investors therefore represents an important measure for assessing the probability of ensuring reliability and security in the long-term. Even where a system has sufficient reserve margins on paper, the day-to-day operations of the market may also suffer where such capacities are not properly maintained or, in the worst case, are wilfully withheld from the market. The first criterion therefore also includes a short-term aspect, i.e. to provide incentives for maximising generator output during periods of scarcity and avoid withholding.

Promoting Economic Efficiency

Although reliability and security of supply are generally regarded as being extremely important, the success in reaching these goals has to be weighed against the direct and indirect costs of each model. As a second criterion, we therefore assess each model with regards to promoting economic efficiency and the costs incurred. This criterion can also be described as ensuring that a sufficient level of generation capacity can be provided at an economically-justified level of costs to the overall system. Moreover, it seems again useful to differentiate between long-term and short effects.

In terms of long-term efficiency, this implies that each model should not only avoid a deficit of capacity (criterion 1) but also minimise any excess capacity. Secondly, where any additional payments are made, these should ideally be targeted at those who need them and/or be compensated through reduced costs elsewhere. Similarly, each model should not cause any distortions with regards to the choice of technologies, whether in the long-term (investment) or daily decisions on scheduling and dispatch. Conversely, some mechanisms may also have a positive influence on short-term efficiency, namely where they help to promote competition by introducing and/or enhancing the price-elasticity of demand.

Compatibility with other Elements of Market Design

The different mechanisms discussed in this report do not represent a true alternative for existing market design models in the sense that they do not allow for a complete replacement of the existing arrangements. Indeed, all of the models discussed in this report can principally be applied in either of the two fundamental electricity market design models, i.e. the choice between centralised pools and bilateral contracts markets with decentralised scheduling. Consequently, they should be seen as supplementary measures aimed at improving the success of the basic market design models. It is therefore essential that the mechanisms discussed in this section are compatible with other elements of the overall market design, including in particular the markets for energy and ancillary services (where these exist). In addition, it is also important that the any potential introduction of these mechanisms avoids creating any additional barriers to entry.

Feasibility and Cost of Implementation

The different models presented in this section typically require the introduction of additional market mechanisms and settlement arrangements, some of which create additional complexity and risks for participation. To supplement the assessment with regards to economic efficiency and the compatibility with the overall market design, this final criterion therefore considers the feasibility and costs of implementation. Besides the complexity of implementation and the direct costs of the corresponding technical and organisational arrangements, this section also includes an analysis of the resulting transaction costs.

3.2 Quantity-Based Capacity Mechanisms

3.2.1 Overview

Quantity-based mechanisms directly address the desired level of reliability by establishing an explicit requirement for a certain level of generation capacity or reserves. Typically the price to be paid for this capacity is not determined in advance but is decided via a separate, often market-based mechanism. A universal feature of any quantity-based mechanism is that it relies on a central planning agency to determine the desired level of a chosen type of capacity. Moreover, most quantity-based mechanisms tend to have some sort of price caps that are based on political decisions on how much society is willing to spend for the availability of capacity.

There are options to apply quantity-based mechanisms to different types of capacity such as installed capacity, firmly available capacity, or the additional ability to provide a certain (ancillary) service, which may require further dynamic capabilities. Similarly, the corresponding requirements may be imposed on individual market participants, typically retailers, or be met through centralized purchases by the System Operator, or another centralised entity.

Overall, the group of quantity-based mechanisms can be divided into several sub-models. In the following, we differentiate between four different approaches:

- Capacity markets (Capacity Obligations);
- Reliability options (Forward Capacity Market);
- Peak load reserves / Essential generators; and
- Operating reserves.

These four different models are presented in more detail in sections 3.2.2 to 3.2.5.

3.2.2 Capacity Markets (Capacity Obligations)

3.2.2.1 Main Characteristics and Application in Practice

Capacity markets were originally developed in some of the U.S. markets, such as PJM (see section 4.2 below), but can now also be found in other regions, like Western Australia or the Russian Federation. They are similar to the cap-and-trade mechanisms used for instance for the trading of carbon or renewable certificates. The underlying rationale of these mechanisms is based on the idea of mimicking the integrated resource planning of a traditional vertically-integrated utility, whilst leaving the decision of how to best achieve these goals to the market. This is achieved by transferring the need for maintaining a certain level of reserve capacity, which traditionally represented an important planning criterion in a vertically-integrated utility, on to individual market participants.

In most cases, the capacity requirement is implemented by creating an explicit requirement on retailers to maintain and/or contract for a certain share of generation capacity. As an alternative, generators and, possibly, interruptible customers are awarded Capacity Tickets which they may then sell to retailers who are not able to fulfil their Capacity Obligations themselves. In order to facilitate this process, an organised market may be established where market participants may trade any excess or shortfall positions with other parties. As an alternative, Capacity Tickets may also be purchased by a single buyer, such as the

System or Market Operator, with the resulting costs being distributed to customers in a similar way as network charges.

The main characteristics of the capacity market model, which are further described in section 3.2.2.2 below, can be described as follows:

- Centralised determination of an explicit requirement for 'firm capacity' to be kept available;
- Award of 'Capacity Tickets' to generators and interruptible customers, taking into account the level of 'firm capacity' they may provide;
- Determination on the volume of Capacity Tickets to be procured by demand;
- Establishment of arrangements for bilateral and/or organised trading of Capacity Tickets;
- Decision on potential price caps and penalties to be paid in case of non-compliance; and
- Settlement and monitoring of compliance by generators and demand.

The detailed design of these mechanisms may vary, for instance with respect to the responsibility for purchasing Capacity Tickets from generators or interruptible customers; i.e. whilst this obligation is typically imposed on retailers, it may also be placed on generators or be fulfilled through the System Operator or a similar centralised entity acting as a single buyer on behalf of all customers. Similarly, the time horizon for Capacity Obligations and Capacity Tickets may range from one day or a week ahead to many years in advance. A final important consideration relates to any restrictions on the pricing of Capacity Tickets and penalties to be paid where a market participant fails to comply with its obligations.

3.2.2.2 Detailed Description

The capacity markets model is based on the definition of an explicit requirement for capacity to be maintained. In order to ensure that the same obligation is placed on every market participant, the overall required volume of capacity has to be centrally established by a single entity, which will usually be the System Operator. However, this responsibility may also be transferred to a separate Market Operator and the final decision may be subject to approval by the regulator. The determination of this value will typically be based on the same principles and criteria as commonly used for system planning purposes and may consider various aspects such as expected demand, reserve requirements and, potentially, any additional capacity which may be firmly available from neighbouring power systems. Depending on the time horizon of the capacity market, the overall capacity requirement may be determined on an annual basis, but may also be varied on a seasonal, monthly, weekly or even daily basis (see below).

The definition and allocation of 'Capacity Tickets' represent the second characteristic element of this market model. Capacity Tickets represent a measure of the 'firm capacity' provided by generators or interruptible load, i.e. the capacity which is deemed to be firmly available on average under peak load conditions. Capacity Tickets are typically based on the installed capacity of the corresponding generating units (or the volume of interruptible load), but with adjustments for maintenance, unplanned outages, limitations due to energy constraints (for instance in case of hydropower plants) or other factors. Depending on the time horizon of the capacity market, these adjustments may either be based on average probabilities, like an average maintenance or outage rate, or known events, such as the maintenance schedule for the next weeks or months. Moreover, the corresponding factors may either be the same for all plants of the same technology, or reflect the historic performance of individual generating units. Finally, Capacity Tickets do not typically take account of specific dynamic capabilities, i.e. they are equally awarded to all generation (or demand reducers) that can be made available within scheduling timescales. Consequently, whilst capacity markets do require some form of pre-qualification and may involve testing of individual units the corresponding arrangements are less specific and thus tend to be less complex than for instance in the case of operating reserves (see section 3.2.5 below).

Unless the overall capacity requirements are centrally purchased by a single buyer, the award of Capacity Tickets is mirrored by the allocation of Capacity Obligations on retailers.[7] This allocation is typically carried out by the same entity that is also responsible for the determination of the overall capacity requirement. Capacity Obligations represent the volume of Capacity Tickets to be bought or maintained by a retailer and are determined in accordance with a fixed set of rules which will typically take account of the (coincident) peak load of the demand served by this retailer, or a similar measure. Depending on the planning horizon of the capacity market, these obligations may also be determined on an annual basis or may vary by season, month or even on a daily basis. Moreover, in a market with locational pricing, it is possible that Capacity Obligations (and Capacity Tickets) refer to specific nodes or regions within the overall market, i.e. that a Capacity Obligation may only be matched by the corresponding volume of Capacity Tickets in the same node or region.

The trading of Capacity Tickets between generators (or interruptible customers) and retailers represents the core market element of this model. Trading will be triggered by the allocation of Capacity Obligations, or by the need to submit traded volumes into the relevant settlement system ahead of the time interval for which they are valid. The mechanisms by which Capacity Tickets may be traded include both bi-laterally negotiated contracts, contracts established via auctions, or centrally administered tendering processes. The duration of the contracts may be for the full year or even multiple years associated with the allocation of purchase obligations, or for shorter periods such as a month or even the day ahead. Once a Capacity Ticket has been purchased, a centrally administered settlement system would receive a notification to that effect and this notification would then be used in settlement to assess the extent to

[7] Principally, this requirement could also be placed directly upon generators.

which a retailer had fulfilled its obligations and the extent to which a generator might be liable for non-delivery, as well as providing the basis for the actual purchase, if this was done under a centrally administered mechanism.

The scope and frequency of trading in a capacity market is strongly influenced by the underlying time horizon and the degree to which Capacity Obligations are adjusted over time. For instance where both Capacity Tickets and Capacity Obligations were allocated on an annual basis and were constant throughout the year, it would principally be sufficient to perform one single round of trading at the year ahead stage. In practice, however, trading of Capacity Tickets usually takes place at periodic times up until the day ahead stage, generally in line with the planning and scheduling regime for the relevant energy market. The need for additional trading may be triggered for instance by adjusting Capacity Obligations in accordance with the expected demand on a, say, monthly or even daily basis, or where generators have to obtain Capacity Tickets to compensate for their own plants being unavailable due to maintenance or unplanned outages. Finally, a retailer’s aggregate obligations for Capacity Tickets may also change where it has either won additional or lost existing customers. Consequently, the administration of the capacity market has to be closely coordinated with the administration of eligible customers and their allocation to different retailers in the energy market.

The final step of the trading arrangements is usually a centrally administered capacity market on the day ahead where market participants may buy or sell Capacity Tickets to cover any remaining deficits or surpluses. This capacity market is compulsory and similar to a net pool for energy, i.e. retailers must buy Capacity Tickets for that share of Capacity Obligations which they have not been able to match through purchases (or self-provision) of Capacity Tickets before, whereas generators (and interruptible load) must offer any remaining Capacity Tickets from all capacity that is also declared available to the energy market.

Although the capacity market should ideally result in a perfect match between supply (Capacity Tickets) and demand (Capacity Obligations), it is accepted that there may be a deficit of capacity or that generators may only offer Capacity Tickets at excessive prices. Similar to other cap-and-trade mechanisms, all capacity markets are therefore subject to a penalty for any failure to procure sufficient capacity. In addition, or alternatively, a price cap is often set on the price which generators may ask for Capacity Tickets in the final stage of the capacity market. The corresponding penalties and/or price caps are ultimately politically set (often by the regulator) but are often intended to reflect the long-run marginal costs of new peaking units. This practice reflects the expectation that a generator’s short-run marginal costs will be recovered via energy sales such that the Capacity Ticket arrangements only need to provide for the recovery of fixed costs that are not already covered through profits earned in the energy market.

The last step of the capacity market involves settlement and monitoring of compliance by both generators and retailers. Settlement may be limited to transactions through the centralised capacity market and will usually be carried out by the same party also responsible for the administration of Capacity Tickets and the centralised capacity market, although the roles of Market Operator and Settlement Administrator may also be separated. Often, the same party will also monitor compliance and check whether generators and retailers have made capacity genuinely available for potential dispatch and obtained sufficient Capacity Tickets, respectively. In the case of retailers, this may also include cases where a retailer's customers have consumed energy in excess of the capacity purchased, for instance as a result of inadequate demand forecasts. Where market participants are found to be in breach of their obligations, they will be subjected to the penalties mentioned above.

3.2.2.3 Qualitative Assessment

The following text briefly assesses the capacity market model along the four main criteria defined in section 3.1 above:

- **Assuring reliability and security of supply**
    - The underlying rationale of the capacity market mechanism is based on the idea of mimicking the integrated resource planning typically undertaken by a traditional vertically-integrated utility, whilst leaving the decision of how to best achieve these goals to the market. The primary focus of this model is therefore on reliability and security of supply. Indeed, provided that the model succeeds in delivering the capacity requirement set by the System Operator, it will lead to the same outcome as the traditional long-term planning of a vertically-integrated utility. Ideally, this model should therefore result in the best possible match between installed capacity and future system requirements.
    - The introduction of Capacity Tickets results in additional payments to generators. In the case of peaking plants in particular, these will tend to result in a more stable income stream, thereby potentially reducing risks for investors. If generators offered capacity at long-run marginal costs, the additional income would furthermore be sufficient to cover the fixed costs of peaking plants, which should provide strong incentives to invest.
    - These positive effects crucially depend on two preconditions, namely that the value of Capacity Tickets reflects the long-run marginal costs of (peaking) plants, and a sufficient level of synchronisation with the time horizon of the capacity market and the planning process of potential investors. In the early arrangements for the capacity markets at PJM and NY this was a concern, (see also section 3.2.2.4 below). The following sub-paragraphs explain these two issues in more detail:
        - First, the volume of Capacity Obligations to be maintained by each retailer is exogenously defined by a centralised entity, resulting in a perfectly inelastic

demand curve. In contrast, the volume of available capacity primarily depends on (past) investment decisions, whereas the short-run marginal costs of providing capacity are basically equivalent to fixed O&M costs.[8] In combination, the price of Capacity Tickets can be expected to fall to a level far below long-run marginal costs in a situation with excess capacity, whereas it will stay at, or close to the price cap in any situation with a deficit of capacity. This effect may result in extremely volatile capacity prices and severely undermine the scope for providing sufficient income certainty for investors; and

- Secondly, it is important to note that investments in new generation capacity involves a considerable lead-time and often has a pay-back time of many years. Conversely, especially during the initial implementation phase of a capacity market the mechanism operates over a very short time horizon of not more than a few months. This leaves little or no opportunity for new entrants to provide additional capacity or to respond to changes in the requirement. In combination with the potential volatility of capacity prices (see above), this may greatly undermine the additional incentives to invest and therefore create further risks for the objective of actually reaching the desired level of capacity.

o The lack of demand elasticity also means that a capacity market with a fixed requirement for capacity may be rather vulnerable to manipulation, namely through withholding of capacity. Especially in case of a relatively short time horizon, this model may therefore provide incentives to withhold capacity rather than making it available to the market.

o Whilst these considerations indicate considerable risks of actually reaching the primary objectives of this model, some of these shortcomings have been addressed by more recent implementations of modifications of the existing mechanisms (see section 3.2.2.4 below). These changes especially include the transition to a longer time horizon (multiple years) for the definition of Capacity Obligations and Tickets, the introduction of a lead time of several years between the trading and the 'delivery' of Capacity Tickets, or the artificial introduction of demand elasticity.

- **Promoting economic efficiency**

o Whilst the capacity market model explicitly defines the desired level of capacity, it relies on a market mechanism to determine the (additional) remuneration for capacity. As mentioned above, the intention therefore is for the market to allow prices to converge to

8 Operating & maintenance costs

the long-run marginal costs of capacity, which should promote long-term efficiency. The above concerns related to the volatility of capacity prices also apply in this case.

- The economic efficiency of the model depends upon the accuracy of setting the socially optimal level of reserve capacity. In this context, it is important to note that the entity being responsible for setting the overall capacity requirement is not itself exposed to the costs of contracting for this capacity. Although the planning process should ideally involve all stakeholders, this creates a potential risk of erring on the side of excess capacity.

- Capacity markets principally cover the entire amount of installed capacity. As a consequence, it is not only peaking plants that benefit from the resulting payments but also other generators that are already profitable in the energy market. This model may therefore result in considerable windfall profits for the latter group and considerable additional costs for consumers.

- Since the capacity market usually ends before the start of the day-ahead energy market there should be no direct interaction. Indirectly, however, the introduction of additional payments for capacity should reduce the need for peaking plants to fully earn their fixed costs through the energy market and provide additional incentives to make capacity available to the market at times of scarcity. A major advantage of the capacity market model is therefore that it improves the short-term efficiency of the energy market by allowing peaking generators to offer at marginal costs and therefore reduces the risk of price spikes.

- Depending on the specific design of the capacity market, this model may create additional incentives for withholding of capacity and thus create additional risks for short-term efficiency.

- **Compatibility with other elements of market design**

  - The capacity market mechanism is an entirely separate market, which does not directly interact with other parts of the overall market design. In principle, therefore it should not represent a source of major concern about the compatibility with the overall market design.

  - The potential incentives for withholding of capacity mentioned above point to a serious area of interaction between the markets for capacity and energy, especially in an interconnected system. KEMA have already commented on the impact of withholding capacity which may raise prices in both the capacity and the energy markets. In addition, where generators have the choice of providing their capacity either to the capacity market or to another market, for instance in the form of exports to neighbouring markets, it may be more profitable to infringe on their obligations under the capacity market and use the same capacity for exporting energy at a much higher price.

- The ability to verify the availability of generators represents a fundamental precondition for this model. Whilst this does not create a problem in pool-type markets with centralised scheduling, it creates a major barrier for the introduction of this model in a bilateral contracts market with decentralised scheduling where the System Operator may not be able to verify the technical availability of generators, or not until the real-time balancing market, i.e. well after the end of the wholesale market.[9]

- The effectiveness and efficiency of the capacity market model may be improved by using a longer time horizon, potentially including a lead time of one or several years. However, these longer time frames may also act as barriers to entry since they will create a disadvantage to any new entrant that has not already been able to sell Capacity Tickets and may find itself being excluded from this mechanism until the end of the current allocation and trading period.

- **Feasibility and costs of implementation**

  - The capacity market mechanism requires establishment of a completely 'parallel market' separate to the energy market, including the administration of Capacity Obligations and Capacity Tickets and the trading and notification of Capacity Tickets. In addition, it is necessary to introduce a mechanism to calculate each retailer's share of the overall capacity requirement and for monitoring and enforcing compliance of both retailers and generators. Implementation and operation of a capacity market therefore represents a complex and costly task.

  - In a bilateral contracts market, the complexity of the capacity market is further increased by the need to verify the effective availability of generators in the absence of a mechanism for centralised scheduling. Similar concerns also apply to an interconnected system where it may be necessary to capture the potential use of generation for exports.

[9] In this context, it is important that some European countries even rely on a voluntary balancing mechanism, i.e. there is no formal requirement to offer capacities into either the wholesale or the balancing market. Moreover, whilst it is often argued that prices in the wholesale market will converge to the prices in the real-time balancing market, practical experience show that often the opposite is true in practice, i.e. generators will structure their bids and offers to the balancing mechanism 'around' the price resulting in the day-ahead and (where available) the intra-day market.

Although proposals for a corresponding mechanism have been developed,[10] these would effectively have required a comprehensive tracking of the trading of Capacity Tickets between different market participants[11] and would have resulted in significant additional complexity.

- o The complexity and costs of implementation are mirrored by considerable transaction costs.

3.2.2.4 Experiences from Practice

The first capacity markets at PJM and NY were put into operation in 1998 and at the end of 1999, respectively. Consequently, one can already rely on practical experience from the first years of operation which have revealed a number of serious design faults in both markets. This resulted in major reforms to both market models in recent years (compare sections 4.2 and 4.2.1).

The difficulties that emerged in the operation of PJM and NY's capacity markets operation include:

- **Market Illiquidity**. Most capacity was procured by retailers through long-term bilateral contracts transacted outside of the PJM-run markets, or by virtue of the fact that the (remaining) vertically integrated utilities in PJM could use their own generation to offset their capacity for serving native load. As a consequence, average MW volumes in the centrally administered capacity markets were relatively low. Generally it has been the smaller companies that have purchased a disproportionate amount of capacity through these auctions.

- **Price Volatility**. Prices in both the PJM and NY markets were quite volatile, reflecting the deterministic nature of the capacity requirement and the resulting lack of demand elasticity as discussed above. These design faults resulted in extremely volatile prices and also presented enormous incentives for the exercise of market power by the withholding of capacity.

- **Incentives for Vertical Integration**. This volatility meant that retailers that had not covered their demand either by building capacity or by signing long-term contracts were exposed to substantial short-term risks. The ability of any company to cover its position (if it does not already own sufficient generation capacity) depends upon the liquidity of capacity markets, which however proved problematic as mentioned above. The capacity market therefore tended to encourage vertical integration between retailers and generators, either by retailers owning generation or through contracts.

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10 Vázquez, Carlos, Carlos Batlle, Michel Rivier and Ignacio Pérez-Arriaga. Security of supply in the Dutch electricity market: the role of reliability options. Report IIT-03-084IC. Universidad Pontificia Comillas. Madrid. 15 December 2003.

11 Similarly to a system targeted at a comprehensive tracking of the exchange of 'Certificates of Origin'

- **De-listing Capacity**. An important problem experienced by PJM was that some sellers of capacity had incentives to de-list their capacity i.e. renege on their capacity obligation at short notice. Depending on market conditions in PJM and neighbouring markets, generators found it to be advantageous to commit to meet loads outside PJM even during times of capacity shortages within PJM. This problem was aggravated by the existence of much higher price spikes in neighbouring systems such as the East Central Area Reliability Coordination Agreement area (ECAR) and the fact capacity could be diverted by delisting a capacity resource with two days notice.[12] As a result, PJM generators were sometimes able to be paid twice for the same capacity; once through capacity payments received during most of the year, and a second time from price spikes in neighbouring systems. Conversely, PJM consumers who paid for capacity did not always receive the capacity when it is most needed.

In terms of the performance of the capacity markets in delivering investment, reliability and security of supply, recent reforms at PJM have led to promising results (see section 3.1):

- The first five RPM[13] auctions have delivered investments to supply 9,986 MW of new resources, including over 2,000 MW of new Demand Response resources. The latter represents an important improvement in view of the fact that PJM had previously experienced a decline in customer willingness to provide curtailment during system emergency conditions. With the implementation of RPM, total load response in the capacity market has increased by over 3,500 MW.

3.2.3 Reliability Options (Forward Capacity Market)

3.2.3.1 Main Characteristics and Application in Practice

The concept of Reliability Options has been developed with a view to addressing the problem of insufficient incentives for the availability of capacity at times of scarcity (see section 3.2.2 above). This model therefore bears many similarities with the capacity market mechanism, whereas the fundamental differences relate to the penalties to be paid by generators in case of non-delivery of committed capacity. The idea of Reliability Options was originally developed for the Colombian market by professor Perez-Arriaga[14] from Spain but was later also taken up by others[15] and has also been discussed for application in

12 Generators who de-list from PJM in times of shortage are subject to penalties, including an installed capacity ("ICAP") deficiency charge and an increase in the outage rate assumed when calculating their unforced capacity quantity (which reduces their "unforced capacity"). However these incentives were widely recognized to be insufficient. With a deficiency penalty of $177/MW-day, a seller of capacity had to see an energy price differential of little more than $10/MWh on a standard 16 hour peak contract to be better off selling his power elsewhere.

13 RPM - Reliability Pricing Model, see section 4.2

14 "Long Term Reliability of Generation in Competitive Wholesale Markets – a Critical Review of Issues and Alternative Options", Ignacio Perez-Arriaga, June 2001.

15 See for example Peter Cramton and Steven Stoft

other markets, including the New England market in the U.S., Romania, Spain and the Netherlands. Whilst this model has been discarded in case of Romania and the Netherlands, it has now been adopted in both Colombia and New England,[16] in the latter case being referred to as the Forward Capacity Market, or FCM. Moreover, some elements of this concept have also been integrated into the recent reforms of both the PJM and NY markets.

Reliability Options are financial instruments that are based on a combination of a financial call option with a high strike price related to the price in a suitably identified reference market (typically the day-ahead energy market), coupled with an explicit and high penalty for non-delivery. Reliability Options are either called-off, or not, by assessing the reference market, at the time that the reference market clears. If the energy price in the relevant reference market is below the strike price, then the contracts would be 'out of the money' and would not be called. If, however, the reference price exceeds the strike price, then the options are called and the generators must reimburse the difference between the strike and reference prices for the contracted volumes. These Reliability Options have to be backed by a physical resource certified as capable of producing firm energy.

The overall requirement for Reliability Options is determined in a similar way as Capacity Obligations in a capacity market. Similarly, corresponding contracts may be centrally purchased by a single entity such as the System Operator, or an obligation may be imposed on retailers to obtain a certain volume of Reliability Options, based for instance on the expected peak load of their customers. However, in contrast to the model described above, a Forward Capacity Market requires a centralised auction of Reliability Options well in advance of actual delivery since this concept has been expressly developed for an extended time horizon of several years or even more.

The main elements of the Reliability Options model can be described as follows:

- Determination of the main parameters of the Forward Capacity Market;
- Contractual and administrative pre-qualification, including credit worthiness;
- Centralised (generally) procurement of Reliability Options;
- Provision of guarantees to back delivery;
- Reconfiguration and secondary market of Reliability Options;
- Call-off of Reliability Options during daily energy market; and

[16] Both markets are currently undergoing a transition period, i.e. auctions have already been held for the procurement of Reliability Options which however refer to future years.

- Settlement and monitoring of compliance.

3.2.3.2 Detailed Description

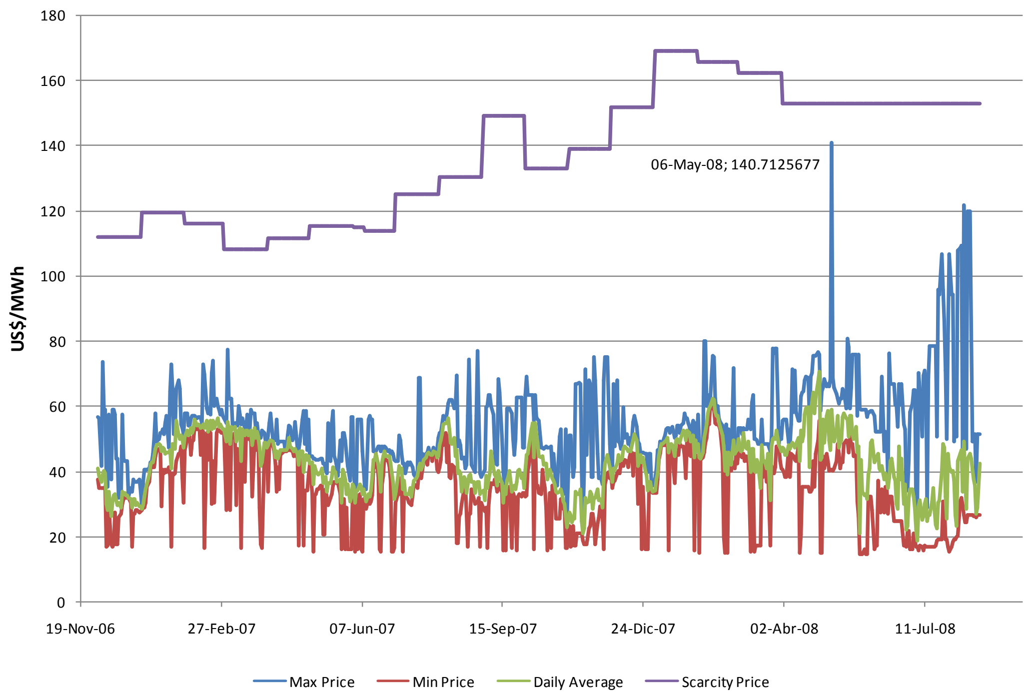
As a first step, it is necessary to set the main parameters of the mechanism, including the volume of Reliability Options to be procured, the planning period (lead time) and commitment period (time horizon) of the auction, the option strike price, the demand curve (willingness to pay for capacity), and the value of the penalty for non-delivery. These parameters may be proposed by the entity responsible for purchasing the Reliability Options but will typically be subject to approval by the regulator.

The volume of capacity can be determined in a similar manner as for capacity markets, i.e. taking into account the future development of demand, the average availability of different types of generation, required reserve margins etc. Alternatively, the lead time for new contracts may have to be based on the time required for the construction of new power plants. The decision on the time horizon represents a discretionary choice, but has to ensure a suitable compromise between limiting the duration of capacity contracts, whilst providing sufficient certainty for investments into new assets (see section 3.2.3.3 below). In both Colombia and New England, the considerations have resulted in a different treatment of new and existing sources of capacity as further explained below.

The objective for the strike price is to avoid being too low such that it acts as a cap on energy prices and avoid being too high, such that options are never called, creating a de-facto energy only market. For the latter reason, the strike price should be much lower than the maximum price that consumers are deemed to be willing to pay (Value of Lost Load, VoLL) since the options would otherwise not have an effect apart from in situations of near rationing. An alternative approach therefore is to use an estimate of the marginal costs which may be experienced by a peaking generator, plus possibly an additional margin. Since this price will tend to be much lower than VoLL consumers will be hedged against the risk of excessive market prices and the use of market power. Conversely, virtually all generators will face strong incentives to produce since the strike price, and hence the possible energy market price, will be above their marginal costs. The additional margin will finally help to account for imperfect estimates and further minimise the risk of the strike price acting as a cap on energy prices.

Given the potentially long time horizon of the auction, it may furthermore be desirable if the strike price is either indexed to some external indicators as illustrated by the example of the 'scarcity price' from Colombia in Figure 5 or adjusted for instance by the regulator on a regular basis.

Figure 5: Daily Adjustment of Scarcity Price for Reliability Options in Colombia



Source: Luis Alejandro Camargo. Capacity Payments Organized as a Financial Coverage - The Colombian experience. 2008 APEx Conference. Sydney. October 2008

Again similar to the capacity market mechanism, any purchases of Reliability Options are subject to price caps. In practice, both Colombia and New England have chosen a demand curve with artificial price elasticity. This demand curve is based on 100% of the desired capacity being purchased at a price equal to the estimated Cost of New Entry (CONE), which is initially estimated by the regulator but shall be adjusted based on the auction results for future tenders. To introduce demand elasticity, slightly less capacity is purchased at higher prices, whereas at lower prices slightly more than the target quantity is purchased. The possible variation in prices is limited to an upper ceiling of two times CONE and a floor of 50% (one-half) times CONE. In addition, offers below 0.75 times CONE are subject to a review by the Market Monitoring Unit in New England, to determine if the offer is consistent with "the long run average cost of that resource net of expected net revenues other than capacity revenues".[17]

Based on the definition of the main parameters of the overall mechanism, the second step involves the pre-qualification of potential capacity providers, which includes contractual and administrative issues. In principle, there may be fewer technical pre-qualifications for a Reliability Option market, by comparison with Capacity Tickets, since the risk of non-delivery falls to the generator. In practice, however, both

[17] Market Rule 1; III.13.1.1.2.6

Colombia and New England have chosen very similar approaches to the one presented above for capacity markets. For instance in Colombia, the potential offering by a generator is based on the level of firm energy, which is defined as the maximum electrical energy a given generation plant is able to produce on a permanent basis, including in case of hydropower under extreme hydrological conditions for a certain period of time. Similarly, New England applies a system which is broadly similar to the measures used by PJM and NYISO for determining the level of firm capacity.

As mentioned above, the concept of a Forward Capacity Market has been specifically designed to allow for the participation of new-built capacity. Prospective generators therefore have to provide additional evidence to show that the proposed project can and will be built if it is successful in the auction. Amongst others, prospective bidders will normally be required to be compliant with any legal and contractual requirements, to have secured appropriate network access beforehand and to submit relevant technical and cost information and a realistic time schedule for realisation of the planned project.

The initial allocation of Reliability Options is achieved through a centralised auction, which may for instance be operated by the System or Market Operator. Participation in the auction is open to all existing and prospective capacity providers that have pre-qualified before. The auction itself and price formation can basically take any possible form. In practice, both Colombia and New England have opted for a descending-clock auction with a single clearing price (within different regions). As already mentioned above, this process may be complicated by the participation of both existing and prospective providers of capacity. To solve this issue, a shorter commitment period is used for existing resources (typically one year), whereas new resources generally have the flexibility of themselves selecting a longer commitment period of several years. Colombia has further allowed new resources with a longer planning period of up to 7 years ahead to participate as price takers.

All successful bidders are required to enter into a Reliability Option Contract with the nominated counter-party (generally the System Operator or Market Operator). In addition, they may be asked to provide financial guarantees to back delivery. For instance new resources may have to submit a construction and commissioning guarantee during the planning period, whereas both existing and new resources may be subject to a (fuel) availability guarantee during the commitment period.

Similar to the case of capacity markets, it is possible that market participants may find themselves in the position where they have either a surplus or a deficit of capacity. For instance, a project may proceed faster or slower than anticipated, or an existing resource may face an extended outage that had not been anticipated before. Likewise, where retailers have to acquire Reliability Options on an individual basis, their needs may change due to faster or slower load growth or customers switching their supplier. Both Colombia and New England therefore do not only allow for bilateral trading of Reliability Options but have also established a system of so-called ‘reconfiguration auctions’. These reconfiguration auctions are comparable with the centralised capacity market discussed in section 3.2.2.2 above and serve to allow capacity providers and retailers to balance their positions in light of improved information. Again, these auctions may follow any form of auction design and price formation principles, and may for instance be performed on an annual, monthly or potentially even daily basis.

As mentioned above, the single most important difference between Reliability Options and a traditional capacity mechanism is the combination of the forward capacity contracts with a financial (call) option, which is exercised whenever the price in the reference market exceeds a certain value. If the reference price exceeds the strike price, then all contracts will be called and the difference between strike and reference price will be reimbursed to the party holding the contract. It should be noted that any generator that is scheduled in the reference market would still secure the reference price for that scheduled generation and thus earn exactly the reference price for every MWh produced within the limits of the capacity contract.

The resulting payments could be settled on a bilateral basis by structuring the underlying contracts as tradeable bilateral agreements, providing for a direct financial compensation between the contract holder and the issuing party. Alternatively, all payments could be centrally made to and from a centralised body being responsible for settlement, which will also be required for the administration of financial guarantees, monitoring of compliance and imposition of penalties.

For capacity providers, these penalties mainly include the difference between actual market prices and the strike price. In addition, further penalties may be imposed, such as consideration of any failures to deliver energy when the call option is exercised in setting the level of firm energy which the capacity provider may sell in the future. Conversely, where retailers are themselves responsible for obtaining a sufficient volume of Forward Capacity Contracts penalties may be required to avoid free-riding on the fact that final market prices in a centralised pool may still be hedged to the strike price due to a surplus of capacity contracted by other market participants.

3.2.3.3 Qualitative Assessment

As the term ‘Forward Capacity Contracts’ suggest the concept of Reliability Options bears many similarities with traditional capacity markets as discussed in section 3.2.2 above. In the following, we therefore focus on a discussion of the similarities and differences with the previous model:

- **Assuring reliability and security of supply**
    - Like capacity markets, Reliability Options are based on the explicit determination of the required capacity or reserve margin by a centralised planning authority. Ideally, it should therefore be successful in delivering reliability and security of supply.

  - Reliability Options aim to promote investments into generation capacity by providing firm payments for capacity. Although capacity providers are faced with the risk of losing a certain share of their income, i.e. whenever the call options are exercised, these losses are limited to the uncertain revenues during periods of high prices. These losses are however likely to be more than out-weighted by the additional and certain income from the option premium, especially taking into account the minimum price to be paid for capacity.

  - In section 3.2.2.3 above, we have discussed two main deficiencies of the original concept of capacity markets, i.e. the inelastic demand curve and the lack of compatibility between the time horizon of the capacity markets and the lifecycle of generating plants. In the concept of Reliability Options as presented, both aspects are addressed by the introduction of virtual demand elasticity and the use of longer Planning and Commitment Periods.

  - Another major concern in the concept of capacity markets is related to the use of a fixed penalty, which will provide incentives to withhold capacity whenever the additional profits to be made are larger than the loss of income from de-listing of capacity, or the penalty to be paid when declaring this capacity unavailable. Conversely, the introduction of the additional call option in the concept of Reliability Options can be expected to provide strong incentives for making capacity availability at times of scarcity as the additional profits (in the energy market) will be captured by the payments to be made whenever the option is exercised.

- **Promoting economic efficiency**

  - In terms of long-term efficiency, Reliability Options are likely to show a similar performance to capacity markets, especially with regards to long-term efficiency.

  - In addition, Reliability Options are likely to provide a major advantage to consumers. This advantage arises in the form of the effective price being set on energy prices, equal to the option strike price with the option component of this model providing an effective hedge against prices spikes which should help to reduce extreme price risks for consumers.

  - Provided that the strike price is set well above the level of variable generation costs the introduction of this implicit price cap should not have any negative impact on the short-term efficiency of the market. However, if the price cap was set too low this might result in serious distortions.

- **Compatibility with other elements of market design**
    - In terms of compatibility with the overall market design, KEMA views Reliability Options as being largely equivalent to traditional capacity markets, subject to the potential distortions if the strike price was set too low.
- **Feasibility and costs of implementation**
    - Again, we do not see any significant differences between the model of Reliability Options and the traditional capacity markets discussed above.

3.2.3.4 Experience from Practice

Reliability Options or Forward Capacity Contracts as presented in this section have recently been introduced in Colombia and New England. However, it should be noted that these auctions have all been for commitment periods starting in the future, whereas existing capacity in both countries is currently remunerated under a transitional scheme.

In Colombia, the first auctions were performed in May 2008, including 8 proposals for Greenfield capacity. Through these auctions, contracts were allocated to 42 existing plants for the initial commitment period from December 2012 to November 2013, and to 3 greenfield projects with a maximum commitment period of 20 years. In addition, a further 6 greenfield projects for new hydropower plants were granted contracts as price takers for a period of up to 25 years in a subsequent auction round in June 2008. As a result, Colombia expects some US-$ 6 billion of investments, with installed capacity growing from slightly more than 13 GW today to some 17.5 GW in 2018, equivalent to an increase of firm energy from approx. 66 TWh/a to more than 90 TWh/a.

3.2.4 Peak Load Reserves (Essential Generators)

3.2.4.1 Main Characteristics and Application in Practice

The models described in the two previous sections are targeted at overall installed capacity. An alternative approach has been in place in Sweden and Finland for several years already (see section 4.7) and focuses on the procurement of only a limited amount of capacity. These reserves, which are known as peak load or strategic reserves, are defined as a set of generating capacities that is kept available for emergency conditions, without normally being used in either the day-ahead or the balancing markets. These reserves are made available to the wholesale and/or balancing market only if there is a shortage of electricity, if market prices (are expected to) exceed a certain threshold and/or if the system operator expects and/or observes a lack of other operating reserves. In Scandinavia, peak load reserves are being contracted (Sweden) and owned/operated (Finland) by the national system operators, which also make available these units to the day-ahead and the balancing markets in accordance with a pre-determined set of rules.

The costs of the reserve, net of any revenues from producing electricity for the market, are recovered from consumers through a separate fee or as a component of transmission and/or system operation charges.

Since these units are expected to operate only sporadically, peak load reserves are currently being provided from old and inefficient units, which is why these reserves sometimes also are referred to as 'mothball reserve'. Nevertheless, the approach could principally also be extended to new-built capacity.

The main elements of this model can be described as follows:

- Determination of the required volume and capabilities of peak load reserves;
- Contracting and maintenance of peak load reserves;
- Offering of peak load reserves into the day-ahead and/or balancing market; and
- Settlement and cost recovery.

Finally, we note that a similar approach is used in Belgium and the Netherlands where system operators have contracted for so-called emergency reserves. These emergency reserves represent a share of so-called tertiary reserves, which is a standard type of operating (replacement) reserves within UCTE. These are made available to the real-time balancing market once all other tertiary reserves are depleted and bear many similarities with the advance procurement of operating reserves as discussed in section 3.2.5 below. However, at least in Belgium, a considerable share of these reserves is provided by old, inefficient units (for instance turbo jets and diesel engines) which would otherwise have long been de-commissioned.

3.2.4.2 Detailed Description

The first step for the procurement of peak load reserves involves a detailed specification of the desired product. Depending on the desired use of peak load reserves for the day-ahead and/or real-time market, they may be subject to different dynamic requirements within the normal timeframes for scheduling of production and operating reserves. At least in case of Sweden and Finland, the decision to activate these reserves (i.e. to effectively make them available to the market on a given day), always has to be taken well in advance, allowing for a relatively long notice time of 1 to 2 days prior to the potential use of these reserves. This allows the units to be maintained in only a limited state of readiness.

The volume of peak load reserves is usually determined by the System Operator,[18] in a similar way as the capacity requirements in the capacity market and reliability options models, i.e. taking into account factors such as forecast demand, available generation, hydrological and other constraints etc.

Once the desired volume of peak load reserves has been set, they may be procured in a similar way as operating reserves (see section 3.2.5 below), i.e. including a process of pre-qualification, offering and selection, possibly using market-based methods (tender). These peak load reserves are often provided by older, inefficient plant, such as open-cycle gas turbines, which might otherwise be mothballed or de-commissioned. This means that the characteristics and performance of the plant may be well known and the extent of technical pre-qualification might be reduced to the System Operator being assured that the plant remained in serviceable condition. In order to be assured of the continuing capability of such plant, including start-up capability, the System Operator would also need to undertake tests of the plant from time to time and any change in characteristics would be taken account of under the contract.

The timeframe for the contracting of peak load reserves will generally tend to be longer than for operating reserves, i.e. one year or more. Moreover, a Peak Load Reserve contract would generally incorporate a contract with the owner to provide operational support, along with appropriate fuel stocks to ensure capability to run on instruction from the System Operator, or possibly on automatic start-up using low frequency relays. Alternatively, the corresponding capacity may be leased or even sold to the system operator who would then also assume responsibility for operation and maintenance.

As already mentioned above peak load reserves shall only be offered into the daily energy and/or balancing market under certain circumstances. This requires a set of pre-defined rules, most importantly under which conditions these reserves may be offered into one or both of the markets and what prices? The preconditions will generally refer to the state of the system, such as the remaining reserve margin, or any (expected) shortages in the energy market, such as a persistent period of very high prices. It is important in defining these rules that the price level should be set high enough not to distort normal market prices, i.e. in a similar way to the strike price under the concept of reliability options.

Based on these rules, the system operator, or another centralised agent, will decide each day whether it is necessary to make these reserves available to the market, instruct the making-available of the units concerned, offer the corresponding capacities into the relevant market(s) and, preferably, inform market participants about the activation of peak load reserves. The actual selection and use of peak load reserves would then take the same route as for any other offer in these markets, the only difference being that the agent being responsible for the peak load reserves would act as contractual counterparty in all corresponding transactions in this case.

[18] Potentially subject to approval by the regulator

The final step of the model involves the settlement of all corresponding costs and payments as well as the recovery of the resulting costs from the market. The latter may for instance be based on the general framework for compensating the costs of system services in each country, such as recovery through network, system operation or balancing charges.

3.2.4.3 Qualitative Assessment

Based on the four main criteria defined in section 3.1 above, we believe that the following aspects are worth mentioning with regards to the evaluation of peak load reserves:

- **Assuring reliability and security of supply**
  - Similar to the two models discussed above, peak load reserves aim at two different objectives, i.e. promoting reliability and sheltering consumers from price spikes. Indeed, one may believe that this model will ensure the desired level of 'peaking capacity'.
  - Delegating the decision to offer these resources into the market to a regulated entity may remove concerns about the withholding of capacity. This is particularly likely if the corresponding decisions are based on a known set of rules.
  - Unlike the two previous models, this approach does not provide any additional income to 'close-to-peaking capacity' (i.e. capacity that may not only be required in the most extreme circumstances, but is still operated relatively infrequently). An unfortunate side effect is the availability of peak load reserves will, when functioning as expected, create a de-facto price cap and thereby reduce the income of other generators during periods of scarcity. As a result, 'close-to-peaking capacity' that is not covered by the peak load reserves scheme may actually face a loss in revenues. This is particularly likely if the price at which peak load reserves may be offered into the market is set too low as this may result in reduced incentives to invest and a reduction in reliability.
- **Promoting economic efficiency**
  - In line with the arguments above, peak load reserves will at best have a negligible impact on the long-term efficiency of investments into new generation capacity, i.e. as long as the resulting price cap has a negligible impact on market prices. In addition, long-term efficiency will be influenced by the mechanism for the procurement and remuneration of the peak load reserves, although the corresponding costs can be expected to have only a minor impact on the total costs of capacity.

- If the price at which peak load reserves may be offered into the market was set too low this might reduce efficiency. Assuming limited incentives to invest into near-peaking capacity, the system might end up with a more frequent lack of capacity under normal circumstances, resulting in more frequent use of peak load reserves at higher prices. This would not only result in higher (average) prices to consumers but also reduce long-term efficiency.

- **Compatibility with other elements of market design**

  - On first sight, the arrangements required for peak load reserves appear to be quite similar to those of operating reserves and therefore should be equally compatible with the overall market design. However, a closer analysis reveals a potentially serious interference with the overall functioning of the energy market. More precisely, the system operator, or a similar entity that is expected to act as neutral facilitator, will start to act in the competitive generation market. This may not only require special dispensation under regulatory rules but may also be the source for serious concerns by other parties about the neutrality of the system operator.

- **Feasibility and costs of implementation**

  - The feasibility and costs of this model are believed to be comparable to the procurement of operating reserves as discussed in section 3.2.5 below.

3.2.4.4 Experience from Practice

Peak load reserves were introduced in Sweden and Finland at the beginning of this decade. As described in section 3.7 the introduction of this model was based on various reasons, which were largely related to ongoing developments at that time. As a consequence, these arrangements effectively took the form of some ad-hoc measures, which could be implemented rather quickly, and focused on avoiding the loss of further capacity through the decommissioning of existing plants. Moreover, the use of peak load reserves was originally seen as a transitional solution for a limited period of time.

It is important to consider this background when assessing the practical performance of this model. First, the detailed arrangements in each country were tailored to a limited number of existing generating units such that it is no surprise that the model succeeded in ensuring the continued availability of these plants. Secondly, the transitional nature of these arrangements also explain why they have been limited to existing plants but do not (yet) provide for participation of new-built capacity. Finally, whilst there have been discussions on the potential for introduction of a permanent form of peak load reserves, no final decisions have been take yet.

3.2.5 Operating Reserves Pricing

3.2.5.1 Main Characteristics and Application in Practice

So far, we have focused on mechanisms aimed at generation adequacy, i.e. the need for the availability of sufficient volumes of generation capacity to meet expected load. Besides generation adequacy, the second major dimension of reliability involves security. This aspect is closely related to the need for operating reserves, i.e. any generation capacity (or demand management) that can be used to cater for any scheduling and dispatch timescale mismatches in demand and generation. As a consequence, all power markets worldwide involve some form of arrangements to ensure the availability of operating reserves, as well as other ancillary services, during real-time operations.

Although the definition of operating reserves varies widely, fast-acting reserves especially often require enhanced dynamic capabilities, which cannot be provided by all types of generating plants. Whilst base load and mid-merit plants tend to be less flexible, hydropower plants as well as gas and oil-fired units provide important sources of corresponding reserves, including for the provision of fast-start capabilities. In addition gas-fired plants also represent the predominant form of peaking plants in many power systems. Any mechanisms aimed at promoting security through specific incentives and/or support may therefore simultaneously help to improve adequacy (and vice versa).

Due to these interrelations, operating reserve arrangements represent another potential instrument for increasing reliability. Whilst these typically tend to focus on security, a modified version of the corresponding arrangements has been proposed as an alternative to the quantity-based mechanisms discussed above, with the specific aim of assuring adequacy. Overall, it therefore seems worthwhile to consider the following three approaches:

- Separate remuneration for plants providing operating reserves;
- Advance procurement of operating reserves; and
- Procurement of extra operating reserves (‘Operating reserve pricing’).

Separate remuneration for plants providing operating reserves

In many electricity markets, generators providing operating reserves are entitled to a separate remuneration, irrespective of whether the corresponding services are actually used in real-time or not. As a typical example, all pool-type markets with centralised scheduling involve some form of mechanism to maintain a certain amount of reserves whilst deciding on the (preliminary) unit scheduling on the day-ahead, or any other time before real-time operations. In many cases, like the Australian NEM, New Zealand, Singapore and several of the U.S. markets, this is based on some form of co-optimisation, with the resulting (shadow) prices for reserves being a direct outcome of the scheduling algorithm. Alternatively, other markets rely on additional steps, which usually involve modifications to the original (reserve-unconstrained) schedule and may result in additional payments to all generating units if these need to be constrained on or off in order to provide reserves.[19] Corresponding models are used for instance in the power pools of Italy or Spain.

Whilst the combined scheduling of energy and reserves is by definition limited to markets with centralised scheduling, a different approach may be equally used in markets with centralised and decentralised scheduling. In this case, generators receive an additional payment whenever they make a certain type of reserves or other ancillary services available to the system. The remuneration may either take the form of fixed lump sum payments for all plants that provide at least a minimum volume of reserves, or may be tied to the actual volume of reserves (in MW) being provided. In both cases, payments are made to all corresponding plants and are not directly limited to a certain volume of reserves.[20] Automatic frequency control probably represents the most common example for the application of this model. In practice, corresponding arrangements are, or have been in use in for instance Finland, Great Britain and Norway, including in the original England & Wales pool.

Advance procurement of operating reserves

Pool-type markets with centralised scheduling have the advantage of always being able to utilise the full amount of available capacity. Conversely, system operators in markets with decentralised scheduling can in theory only use those capacities that have not already been committed in the bilateral market. As a consequence, all markets with decentralised scheduling therefore include some mechanisms to ensure the availability of sufficient volumes of operating reserves (and other ancillary services), typically through advance procurement of the corresponding services.[21] Although a variety of different mechanisms are used, there is an increasing trend towards the use of market-based mechanisms, i.e. tenders for reserve capacity, which are often combined with an obligation to bid the corresponding volumes into the real-time balancing mechanism on a daily basis.

Corresponding reserve tenders are today used in most European countries, including Great Britain (see section 3.4), the four Nordic countries (section 3.7), as well as Austria, Belgium, the Czech Republic, France, Germany, Hungary, the Netherlands, Romania and Switzerland. In addition, we note that a similar mechanism is also used for frequency-keeping in New Zealand, mainly due to the specific requirements of the corresponding service (resulting in a lack of competition for integration into the daily spot market).

[19] Please note that these steps may overlap with the consideration of network constraints.

[20] Strictly speaking, this approach therefore represents some form of the price-based mechanisms which are discussed in section 3.3 below.

[21] In some countries, this aspect is solved through some tacit and/or internal agreements within an integrated utility or with a dominant generator such that the corresponding constraints and payments (if any) are not visible.

Procurement of extra operating reserves ('Operating reserve pricing')

A possible extension of these approaches for the procurement of operating reserves has been proposed by Steven Stoft.[22] This approach, which aims at promoting generation adequacy, may also be considered a variation of the peak load reserves model discussed in the previous section 3.2.4. It is based on the procurement of additional reserves, over and above those normally required by the system operator for operational purposes. To minimise any distortions of the market, and to avoid any artificial shortages in the wholesale market, the volume of reserves purchased by the system operator varies with the price, in a similar way as explained for the recent modifications of the capacity markets at PJM and NY (see section 3.2.2), or the concept of Reliability Options (see section 3.2.3). As a result, excess operating reserves are gradually released to the energy market as reserve (and energy) prices increases, whereas additional generators may benefit from these purchases if prices decrease.

Despite the potential merits of the proposed approach, we are not aware of any market where this model has actually been implemented in practice. Consequently, we do not consider it for our further analysis. Similarly, we refrain from a further discussion of the treatment of reserves in a pool market with centralised scheduling since co-optimisation of reserves and energy already constitutes an integral component of the NEM. In the remainder of this section, we therefore focus on the advance procurement of operating reserves, with particular emphasis on the situation in a bilateral contracts market.

The main elements for the tendering of operating reserves can be described as follows:

- Selection of operating reserves and procurement mechanisms;
- Pre-qualification of potential service providers;
- Determination of required volumes and frequency of reserve tenders;
- Purchasing of required volumes through public tenders;
- Call-off via the scheduling and dispatch arrangements; and
- Monitoring and post-event settlement.

3.2.5.2 Detailed Description

The usual first step in this process is for the System Operator to decide on the types and definition of reserves and the mechanism to be used for procurement of each service. Whilst the definition and

[22] Stoft, S.E. 2002. Power System Economics: Designing Markets for Electricity. Piscataway (NJ), IEEE Press; and Stoft, Steven. The Demand for Operating Reserves: Key to Price Spikes and Investment . IEEE Manuscript. January 9, 2003

categorisation of different reserves will usually be based on common technical requirements specified in the Grid Code or similar technical documents, the choice of a suitable mechanism also has to consider other aspects. Most importantly, it needs to be considered whether there is sufficient scope for competition, which is often not the case, especially in case of smaller markets and/or highly-specialised services with specific requirements.[23] This may result in the need to rely on negotiated and/or regulated contracts, or the threat of regulatory intervention to nevertheless enable a market-based procurement.

As is usually the case for Ancillary Service provision in general, the technical capabilities of the plant to be offered must first have been described and validated, typically in the context of requirements that are set down in operational codes. Plant characteristics will normally include some minimum mandated capabilities for providing frequency response and energy ramping and may specify additional capabilities which may already have been tested during commissioning. Once a generating plant has satisfied these and other technical capabilities and has acceded to the relevant connection and use-of-system agreements, such plant can be offered for Ancillary Service provision. Especially in case of repeated tenders, pre-qualified service providers are sometimes invited to sign a framework agreement, which already contains all general contractual stipulations and reduces the subsequent purchasing mechanism to determining the quantities to be purchased from different services providers and the prices to be paid.

Similar to the case of the other quantity-based mechanisms discussed above, system operators will need to determine the volumes of reserves which they want to purchase from the market. These requirements need to be differentiated by type of reserves and may vary over time, such as on an annual, monthly, weekly, daily or even hourly basis. In addition, it is necessary to determine the frequency and time horizon of different tenders, and the share of reserves to be purchased at each stage. In practice, most European system operators tend to procure reserves for periods of 1 – 3 months. However, Belgium and the Netherlands use annual contracts,[24] whereas the system operators in Austria and Germany purchase 15-minute reserves on a weekly and daily basis, respectively.[25]

The actual purchasing process is then based on public tenders, which are commonly carried out by the system operators themselves, but may also be organised by a separate market operator or settlement administration, such as in the case of Austria or the Czech Republic. The form of the tender and price formation may again vary widely. In practice, most markets tend to use single-round auctions with sealed bids, whereas successful offers may be remunerated either at the offer or the marginal price.

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[23] Regulation (AGC), also referred to as frequency keeping (New Zealand) or secondary frequency control (UCTE), represents a typical example. In various countries, this service can be provided by a limited number of plants only, which sometimes are owned by one of just very few countries.

[24] In some cases, even longer periods of several years are used, but usually only in combination with procurement through individually negotiated or standard agreements, i.e. without any market-based selection and pricing.

[25] In case of Germany, these daily tenders are performed before the start of the day-ahead market at the power exchange.

The last steps involve the call-off of reserves via the scheduling and dispatch arrangements, monitoring of performance and delivery, and post-event settlement. These steps are not conceptually different from the usual mechanisms for the use and settlement of reserves in any other markets. However, it is important to note that the advance contracting of reserves is typically based on a portfolio approach, i.e. even where the deployment of reserves and balancing services is carried out on a unit basis, generators (or consumers) often keep the flexibility to themselves decide on the allocation of their overall reserve obligations on individual plants on the day-ahead or even close to real time.

3.2.5.3 Qualitative Assessment

The following text briefly assesses the impact of the operating reserves model along the four main criteria defined in section 3.1 above, focusing on the provision of a separate remuneration and advance procurement of reserves as well as on the different to the other mechanisms discussed above:

- **Assuring reliability and security of supply**
    - As mentioned above, the mechanisms presented in this section 3.2.5 primarily aim at promoting security. Given that the required volumes of operating reserves are either purchased in advance (in a market with decentralised scheduling) or taken into account during the day-ahead scheduling process (in a market with centralised scheduling), it seems reasonable to assume that this objective will be met, at least in the short-term.[26]
    - Similarly, a separate remuneration for reserves will also promote security in the long-term, provided that generators (or consumers) expect a sufficient source of (additional) income from these payments. Given that operating reserves tend to be paid and/or contracted for on a short-term basis, usually not more than one year in advance, the long-term impact of the approaches described in this section can thus be compared with those of capacity payments as discussed in section 3.3 below.
    - Besides the promotion of security, the pricing and/or contracting of reserves may also have a positive impact on adequacy. Indeed, a considerable share of the corresponding remuneration may be paid to peaking plants or other units that are not commonly dispatched on a day-to-day basis. Ideally, these payments may thus function as some form of a price-based capacity mechanism that is dedicated to a limited number of plants.

[26] In practice, there have been cases where system operators were not initially able to satisfy their full demand of reserves. These were however related to the procurement of 15-minutes reserves on the day-ahead, i.e. at a time when generation capacities are already committed under bilateral contracts and when there is insufficient time for a second tender. In our view, these cases therefore indicate deficiencies in the timing of the corresponding tenders rather than a general shortcoming of the model itself.

- In practice, however, most operating reserves require the corresponding units to either be synchronised with the system or have fast-start capabilities. This limits the positive effects on generation adequacy to certain technologies and excludes in particular units that can be built and/or maintained with limited fixed costs but have a low efficiency and can only be activated within normal scheduling timescales. In contrast to, for instance, the peak load reserves model discussed above, this approach is therefore less likely to prevent the decommissioning of old units that are no longer competitive in the energy market under normal circumstances, which represents a considerable risk especially in a hydro-dominated system.

- In terms of manipulation and the withholding of capacity, either of the models described in this section are largely comparable to the situation in an energy-only market. In the case of a pool with co-optimisation, withholding of capacity may have a negative impact on prices in the energy market, the operating reserves market or, in the worst cases, on both markets simultaneously. Similarly, advance tenders for reserve capacity are equally vulnerable to withholding of capacity, mainly due to the lack of demand elasticity.

- The operating reserves pricing model proposed by Stoft addresses these problems by introducing demand elasticity and purchasing additional volumes of reserve capacity, which may include a separate product for 'slow reserves' that can only be activated within normal scheduling timescales. However, success in overcoming these problems crucially depends on the system operator, or the regulator, correctly estimating the relation between the maximum volume of excess reserves to be purchased, the prices to be paid (i.e. the demand curve), the share of payments actually received by different types of generators, and the fixed costs of (close-to) peaking plants. In addition this model faces the same problems as capacity payments in relation to regulatory uncertainty (see section 3.3 below).

- **Promoting economic efficiency**

  - The performance of the market-based models discussed in this chapter can be compared to the case of capacity markets (see section 3.2.2 above), i.e. whilst the desired level of capacity is centrally defined, they rely on the market to determine the price of reserve capacity. This should result in prices converging to short-run marginal costs. Although the advance procurement of reserves in a bilateral contracts market will inevitably result in some loss of efficiency, due to the time lag between the procurement of reserves and the scheduling of generating plants for the energy market, it can be expected to improve short-term efficiency through market based pricing of reserves.

- Similarly, the market-based remuneration of reserves will promote long-term efficiency. Market participants will take into account the combined income from both the energy and the reserve markets when deciding on the technology of new generating units and/or investments into demand-side measures. Assuming that average energy and reserve prices will converge to long-run marginal costs in the long-term, this should ideally lead to optimal investment decisions.

- Long-term efficiency may however be impaired by uncertainty on future income, including from price spikes in the energy and reserve markets. This may result in incentives to invest into less capital-intensive plants, even if these also have a lower efficiency. Furthermore, where operating reserves can be provided from different technologies, performance in this respect depends on prices being sufficiently high during periods of scarcity.

- By definition, reserve pricing is limited to only a sub-set of installed capacity. At least a part of the corresponding payments will only be available to capacity that is not otherwise used in the energy market. This implies that the impact of reserve prices on the overall costs of energy will be much lower than those of energy prices, mitigating the impact of price spikes and allowing for a larger specific income from related payments than under the models presented in sections 3.2.2 and 3.2.3. Simultaneously, one may expect a much lower degree of potential windfall profits for other generators.

- In many countries, the markets for operating reserves are even more concentrated than the energy market. As a consequence, operating reserve markets are more likely to be vulnerable to manipulation by dominant players. There may therefore be an increased risk of prices being above marginal cost, which would have a detrimental effect on both short- and long-term efficiency.

- **Compatibility with other elements of market design**

  - The level of integration between the market-based pricing of operating reserves and the energy market depends on the fundamental design of the energy market, i.e. the choice between a pool or a bilateral contracts market. Indeed, the two main approaches discussed above have been developed to best accommodate the procurement of reserves within the corresponding market design model. In general, we therefore believe that market-based pricing of operating reserves is fully compatible with other elements of the market design, provided that each approach is used in combination with the overall market model for which it has been designed.

- The concerns related to the risk of market manipulation and the often increased level of concentration in the reserves market indicate that the scope for competition may be different in the two different markets, especially where the provision of reserves is subject to additional locational constraints.[27] Consequently, it may not always be possible to establish a functioning mechanism for the market-based pricing of operating reserves even where a competitive energy market exists.

- **Feasibility and costs of implementation**

  - Market-based pricing of operating reserves requires the introduction of additional elements, either within the overall arrangements for centralised scheduling, or a separate mechanism for the tendering and settlement of reserves. Although this naturally creates additional complexity, we believe that the corresponding costs are limited: Whilst market-based pricing mainly requires an adjustment of the existing arrangements for bidding, clearing and settlement in a pool, the advance procurement of reserves in bilateral contracts markets is usually based on relatively simple tender mechanisms, which are far less complex than the arrangements described in section 1.a above.

  - Similarly, we also assess the additional transaction costs as limited, due mainly to the prevalent choice of a direct procurement of reserves by a single central entity, i.e. either through the pool or by means of reserve tenders.

3.2.5.4 Experience from Practice

Many electricity markets throughout the world include some sort of market-based mechanisms for the procurement and/or commitment of reserves. Consequently, there is ample evidence of the day-to-day operations of these arrangements, although it is more difficult to assess their isolated impact on the overall development in each market.

Amongst others, we note the following experiences:

- It is difficult to assess whether operating reserve arrangements have been successful in assuring security since most system operators will normally constrain transactions in the wholesale market before allowing for insufficient levels of reserve margins. As a result, any problems will usually become visible in the energy market first, highlighting the close interaction between the energy and reserve markets.

[27] This is typically the case in interconnected systems where energy may be freely transferred between different markets, subject to transmission constraints, whereas reserves are kept on a national or regional level.

- There are however various examples where the remuneration resulting from reserve markets has been successful in making new capacities available to the market.
    - In various countries, including Austria, Germany as well as a number of Central and Eastern European countries, the additional income from reserves has triggered producers and consumers alike to either invest into existing plants, or to modify their plans for new-built capacity, resulting in additional volumes of fast-acting reserves becoming available to the system.
    - Similarly, we are aware of various cases where the additional revenues from the reserve market have been decisive in the decision for the construction of new plants.
- Various countries have faced difficulties in implementing competitive reserve markets, whether separate from or integrated with the energy market, reflecting the issue of insufficient scope for competition in various countries. For illustration, Belgium, Denmark or Romania have effectively had to partially rely on negotiated contracts, due to the existence of sometimes only one dominant provider of some types of operating reserves.
- Similarly, there have been concerns about the level of reserve market prices in various countries and the possible exercise of market power:
    - For instance in Germany, there have been several cases where prices in the reserve markets increased without any obvious reasons as well as marked difference between the development in the market for 15-minute reserves, with a considerable number and share of smaller participants, and those for frequency control and regulation, which remain highly concentrated. Conversely, the transition to a nation-wide market in 2006 initially led to reduced prices.
    - In Austria, reserve prices arguably decreased following the transition from monthly to weekly tenders, which facilitated the participation of smaller hydropower plants with daily or weekly storage capabilities.
    - The Singapore electricity market experienced a period of extremely high prices for regulation[28] in late 2006/early 2007, without any parallel increase of prices for energy and reserves (which are co-optimised with regulation). Although subsequent investigations found that this development might be explained by technical factors, this situation highlights the potential vulnerability of operating reserve markets to certain events in the power market.

[28] Regulation corresponds to the use of regulation raise/lower reserves in the NEM.

3.3 Price-Based Capacity Mechanisms (Capacity Payments)

3.3.1 Main Characteristics and Application in Practice

The principal objective of a price-based capacity mechanism is the same as quantity-based capacity mechanisms, namely to provide additional assurance that security of supply will be maintained. Rather than setting a target capacity, however, this model takes an indirect approach whereby certain payments ('Capacity Payments') are made to generators per MW based on their availability (whether they get dispatched or not), or based on generated energy as an adder to the energy market clearing price. The capacity payments are collected from customers as a prorated uplift similarly to other uplift charges such as transmission charge.

Price-based capacity mechanisms operate in tandem with energy markets. Since energy markets are based around the scheduling and dispatch processes, availability of generation at the scheduling stage can also be used as the basis for the offer of capacity and a capacity price can be calculated alongside an energy price and allocated accordingly. In order for such a capacity price to be allocated to all qualifying generation, this approach necessarily implies that all demand and generation to meet that demand should be subject to this scheduling process, which is to say a centralized pool type approach.

Post-event, outturn can then be used for any reconciliation, both for energy and capacity. Hence, the capacity arrangements can be established for the same time intervals as those used for energy and the rules for determining such prices and their allocation to availability can be incorporated into the energy agreements and rules documents.

As further explained below, price-based mechanisms can be roughly divided into two main approaches: Under a fixed-fee approach, capacity payments are first determined on a global level and then distributed to individual generators broadly based on their contribution to system reliability. Conversely, capacity payments may also be derived as a function of the actual reserve margin on each day. Where pricing under a fixed-fee approach typically relates to the annualised price of new, peak generation, the second approach is usually related to (estimated) price of reducing demand.

Capacity payments were first introduced in the Chilean market back in 1982 and are now being used for instance in Spain, the Irish SEM (see section 4.6) and several South American countries including Argentina, Chile and Peru. In addition, capacity payments were a part of the market arrangements in the original England & Wales pool (until 2001), the former Northern Ireland market and in Colombia.[29]

The following section provides further details on;

[29] Until being replaced by Reliability Options recently, see section 3.2.3

- Pre-conditions being similar to those for Reliability Options;
- The intervals and periods being integrated with energy trading, with capacity declarations submitted into scheduling;
- Pricing arrangements; being either a cost-based derivation (fixed fee), or a value-based derivation (margin based and related to Value of Lost Load, VOLL) and weighting using a Loss of Load Probability (LOLP);
- Post event settlement processes paying against submitted availability, subject to mismatches with outturn;
- Testing; and
- Regulatory oversight.

3.3.2 Detailed Description

The pre-conditions for trading under a Price-Based Capacity mechanism (as a part of a pool based energy trading arrangement) are fairly similar to the quantity based capacity mechanism as they may be simply based on the capacity being available each day. However, the capacity installed at each generating plant will have been subject to some form of proving as part of the original commissioning processes and connection process.

As in pool based approaches without a capacity price, availability to provide energy is submitted in scheduling timescales, covering each trading interval (perhaps hourly, or ½ hourly) for the relevant scheduling period. As an example, one day ahead for the following day and as each schedule is cleared, all submitted availability would be accepted as submissions of capacity, to be paid for at the calculated capacity price. Submissions normally relate to individual generating units, or power plant installations. Availability would typically be based on capacity, net of on-site load and subject to correction for any allocation of system losses.

As with other forms of capacity mechanism, the expectation is that the capacity payments allow for the recovery of fixed cost, leaving short-run marginal costs to be recovered via energy payments. Two alternatives are generally employed to establish a capacity price:

- Fixed fees (which could be described as being cost based); or
- Margin derived (in essence, a value based price).

For both approaches, a number of pre-determinants are needed, typically ahead of each year:

- The fixed fee approach requires a market administrator, with regulatory approval, or in some cases the regulatory authorities themselves, to establish a reference cost for new capacity, to identify what quantity of new capacity should be incentivised and to set relevant parameters such that this amount can be smeared across each trading interval within the year, as each pool schedule runs. The reference price is normally derived from an assessment of the fixed costs of a new entrant peaking plant. The quantity required is typically derived from assessments of a capacity requirement, which itself is derived from an estimation of the margins between what generating capacity is forecast for the year and demand forecasts for the same period, taking due account of any interconnector flows and reserve carrying requirements. Any identified shortfall between the planning margin and that required to maintain the generation security standard for the jurisdiction is then deemed to constitute a requirement for new investment. Weighting across trading intervals can then be established on the basis of a number of parameters within schedules, such as; demand forecast, plant margins, or some form of Loss of Load Probability (LOLP).

- The margin derived approach requires some underlying value of capacity to be established and this may need to be reviewed by the regulatory authorities each year. The value of capacity that is used may well be an explicit amount established under regulations or legislation and is normally referred to as a Value of Lost Load (VLL). This typically high value (being an estimate of the highest price that end-consumers would be prepared to pay for electricity) would then be factored by a LOLP figure and adjusted for the energy price cleared for the particular trading interval (for scheduled plant) and for any other prices derived from the schedule that might accrue to unscheduled or constrained generation.

The calculation of LOLP would be undertaken within the pool scheduling processes (which may be ex-ante, ex-post, or a combination of the two) and would be derived from a comparison of demand forecast and generation availability. These would each be modified by a probabilistic assessment of the uncertainties of each, based on historic forecasting and generation performance and the resultant probability that demand would actually exceed generation in a given trading interval. Technically, an ex-post calculation of this sort would yield either 1 or 0, although an alternative that is sometimes adopted is to use ex-post demand and generation availability, but with ex-ante probabilities of variation applied. LOLP calculations may also have to take due account of demand elasticity, the intended pattern of any pump storage facilities and may be subject to some form of smoothing across specified trading intervals.

Post-event settlement would then allocate capacity payments to generation. Such payments would be based on scheduled availability, possibly modified if there had been any failure to deliver instructed energy (which might then also involve some back-dating to a point where declared availabilities could be proven). Liabilities to pay for this capacity would normally fall to retailers, pro-rata on outturn demand.

In addition to any technical pre-qualifications that are required when generation first connects to the network, the pool rules (or associated operating code rules) may also allow for the market administrator, or the System Operator, to test the declared availabilities of plant, particularly where such plant does not normally run, or where there has been a failure to deliver against instruction. The outcome of any such tests can then be used to establish a true availability for the plant in question.

As well as the approval of key parameters, such as VOLL and the cost of new entrant peaking plant, regulatory authorities would also be involved in reviewing the operation and outturn of these types of capacity mechanisms, as part of normal market monitoring activity

3.3.3 Qualitative Assessment

The following text briefly assesses the application of capacity payments along the four main criteria defined in section 3.1 above:

- **Assuring reliability and security of supply**
    - Similar to the mechanisms discussed in section 3.2, capacity payments aim at promoting reliability by stabilising the revenues of generators. The remuneration received in form of capacity payments shall provide a relatively stable income stream and thereby help to reduce uncertainty for investors.
    - The performance of this model in delivering investments therefore depends on providing an income that is sufficient to ensure the commercial viability of both existing and new resources. In particular if the level of capacity payments is set too low, the model may deliver less capacity than required.
    - Given the practical difficulties in determining the volume and allocation of payments to generators (see below) and the fact that the level of payments is regularly adjusted, typically on an annual basis, price-based mechanisms may be subject to considerable regulatory uncertainty. Especially in countries with an unstable regulatory framework, this may seriously undermine the credibility of the model and the incentives for investors.
    - Under a system of fixed payments, market participants will not receive any additional incentives to make capacity available at time of shortage. Conversely, in case of dynamic payments (margin derived), if the mechanism is not well designed or if generators can exercise market power, then the economic signals presented by the mechanism may result in generators distorting their behaviour to capitalise on the payments available to them.

- **Promoting economic efficiency**
    - The approach lacks any formal commercial or market basis – there is no tangible product being paid for that can be traded, there is no specific commitment from the generators and the desired level of adequacy cannot be guaranteed. This means that an economically inefficient outcome is likely.
    - Similar to the concept of capacity markets, this model provides additional payments to all types of generators, i.e. the entire volume of installed capacity. Consequently, capacity payments will result in additional costs.
- **Compatibility with other elements of market design**
    - On first sight, capacity payments simply represent an additional income to generators, which is not influenced by daily decisions on unit commitment and dispatch, and vice versa. Especially the concept of fixed payments should therefore be fully compatible with the day-to-day operation of the overall market.
    - In contrast, under a system of dynamic capacity payments, the scope for manipulation may actually reinforce problems related to the impact of withholding capacity in the energy market.
    - Similar to the case of the capacity markets, the ability to verify the availability of generators represents a fundamental precondition for this model. In our view, the application of a price-based mechanism is therefore effectively limited to a market with centralised scheduling.
- **Feasibility and costs of implementation**
    - The implementation of capacity payments is similar to the collection of transmission charges or other charges or payments being made in the electricity market. The daily operation of this model does therefore not involve any significant costs.
    - In practice, there are often serious practical difficulties in determining the volume and allocation of payments to generators, particularly between hydro and fossil generators, which result in repeated disputes between the regulator, the companies and the system operator. This aspect therefore represents a potentially serious issue for implementation, not the least due to its major impact on delivering investments and efficiency.

3.3.4 Experience from Practice

The experiences with the application of capacity payments have been mixed:

- Although for instance England & Wales Pool and Spain experienced a considerable growth of capacity it has been argued that the corresponding investments had other reasons than the incentive from capacity payments.

- Conversely, several Latin American countries have had serious problems in attracting investments into generation capacities despite the application of capacity payments. For instance Colombia continued to experience extremely volatile prices due to climatic effects (El Niño, Niña) as it was unable to increase the share of fossil fuel fired plants.

- In Peru, the application of fixed capacity payments arguably contributed to an unbalanced generation mix, consisting of cheap base load plants and very expensive peaking units.

- The overall direct costs in different countries varies widely, ranging from for instance 10% in Spain to more than 50% of total payments to generators in Colombia.

The England & Wales Pool finally provides a number of practical lessons with the difficulties of implementing a price based capacity mechanism. This scheme had capacity payments made to each generator available in a particular half hour based on the VOLL and LOLP.

The capacity mechanism was criticised for being prone to manipulation through capacity withholding which meant that capacity payments would increase and indeed preventative mechanisms were put in place to smooth the effect of a sudden withdrawal of plant[30]. Some evidence for potential manipulation can be seen in the latter years of the pool which showed increasing Capacity payments. Indeed the last year of the Pool recorded the highest capacity payments, despite the capacity margin being high at 25.3%. However, there were other factors such as customers receiving availability payments that drove some of this increase.

Professor Richard Green suggested that the abnormal levels of payments were not due to strategic capacity withdrawal, but instead by the anomalous way in which the availability factor of new plant was calculated.[31] The governance of the Pool also made it difficult to introduce changes to the calculations as the members of the Pool had to agree to such changes being implemented.

[30] The 8 day rule was introduced to smooth the effects of a sudden withdrawal of capacity by any generator by assessing gensets availability profile over a 8 day period

[31] Green, R (2004) 'Did English Generators play Cournot? Capacity Withholding in the Electricity Pool' CMI Working Paper 41, March

Other possible issues were around the computer programme used to calculate LOLP. David Newbery, a Cambridge Professor, argued that the way disappearance ratios were calculated systematically underestimated the amount of capacity available and despatched at peak times[32]. This issue made the capacity payments easier for generators to game. As an example an unplanned outage at a plant in one month could significantly increase the LOLP and hence capacity payments in the following months. In addition any demand reduction offered by large customer (who received capacity payments) were not included in the VOLL calculations and therefore increased the total level of capacity payments. .

Conversely, Newbery also argued that the administratively set VOLL was probably underestimated based on price elasticities. It could be argued that the over estimation of LOLP was partially compensated by the underestimation of VOLL. However, the relative weight of each component would influence the riskiness of investing in reserve generation capacity. It could be argued that an over estimated LOLP with a relatively low VOLL many have been a politically strategic choice to allow a relatively constant flow of revenues and therefore encourage new generation.[33]

3.4 Establishment of Long-Term Bilateral Contracts

3.4.1 Main Characteristics and Application in Practice

The principal objective of a bi-lateral contracting regime is to allow parties to fix volumes and prices for products traded within an electricity market, to hedge against the uncertainty of spot or short-term pricing regimes and gain certainty for their accruals and liabilities for the medium and longer term. In terms of reliability, bilateral contracts may therefore promote incentives to invest by stabilising the expected income of generators. It is important to note that corresponding effects are not necessarily limited to a bilateral contracts market but may equally be achieved in a pool with centralised scheduling. Similarly, the transition to a bilateral contracts market may not in itself help to realise the potential gains from bilateral contracts with regards to long-term reliability.

In this section, we therefore do not discuss the general choice of a bilateral contracts market with decentralised scheduling as opposed to a pool with centralised scheduling. Instead, we focus on the use of long-term bilateral contracts in both market design models, with the specific aim of promoting reliability and investments into new generation capacities.

[32] Newbery D (1998b) ‘Pool Reform and Competition in Electricity’ in M. Beesley (ed.) Regulating Utilities: Understanding the Issues London Institute of Economic Affairs

[33] Roques, Newbery & Nutall, (2005) Investment Incentives and Electricity Market Design: the British Experience, Review of Network Economics, Vol 4, Issue 2

Bilateral contracts are commonly used in both centralised pools and bilateral contracts markets, either in the form of physical or financial contracts.[34] Depending on the stage of development and the level of liquidity, contracts may be traded up to several years in advance and both in the bilateral market as well as in organised market places, such as a power exchange. However, even in those markets that are generally considered as the most advanced, like the Nordic or the German electricity markets, most forward trading is limited to a maximum time horizon of up to 2 years ahead, although it may be possible to trade up to 3 or even 5 years in advance.

In various cases, additional long-term contracts have therefore been agreed, or even been directed by regulators, mainly for the following reasons:

- Long-term Power Purchase Agreements (PPA)
    - Long-term PPAs have a long history, dating back to sales by independent power producers or autoproducers to vertically-integrated utilities before liberalisation. Under a PPA, the contractual parties typically agree on a fixed set of prices and quantities, subject to indexation of prices to some external indicators and a certain flexibility in terms of volumes, for instance to allow for planned and unplanned outages in demand. As a general rule, long-term PPAs have generally been used in relation with investments into generation capacity, although similar schemes are also in use especially for energy-intensive customers.
- Vesting contracts
    - Market opening and privatisation have been the reason for a different type of long-term contracts. In this case, typically the regulator or the government establishes a set of contracts between different generators and supply companies, providing for the delivery of a fixed amount of energy over the contract period. Although such contracts may also involve some volume flexibility, it is also possible that they only cover a partial share of the total capacity or consumption of the generator and retailer, respectively, with the remaining volumes to be sold or bought in the market.

The detailed arrangements for the implementation of such contracts vary widely. We therefore refrain from a detailed description, but focus on the evaluation of long-term contracts with regards to reliability.

[34] Whilst gross pools only allow for the use of financial contracts, physical contracts may be used in both net pools and bilateral contracts markets.

3.4.2 Qualitative Assessment

The following text evaluates the use of bilateral contracts with regards to the main criteria defined in section 3.1 above:

- **Assuring reliability and security of supply**
  - Firm bilateral contracts provide for a perfect hedge of both producers and consumers with a view to ensuring a fixed income, on the one side, and removing the risk of increasing prices (and hence costs), on the other side. In principle, long-term contracts therefore represent a very effective instrument for minimising uncertainty and enabling major investments as also illustrated by the wide-spread use of long-term contracts in the natural gas industry.
  - In contrast to the situation in a vertically-integrated industry, however, bilateral contracts in a liberalised electricity market are commonly based on the trading of energy rather than capacity. Moreover, it seems reasonable to expect that many buyers, i.e. large consumers and retailers, will tend to demand a certain discount in exchange for engaging into a long-term transaction. Both aspects imply that market participants may find it easier to agree on contracts for base-load energy. Conversely, it seems less likely that peaking plants will be able to find a counterparty that is willing to pay more than the equivalent of the average market price.
  - Based on these considerations, it appears that voluntary long-term contracts are more likely to represent a potential option for investments into capital-intensive base load plants, whilst they may be less suited for (super-) peaking[35] generators, which are commonly believed to be at the heart of the problem of ensuring reliability. Consequently, it seems rather questionable whether voluntary long-term contracts represent a feasible option for ensuring generation adequacy in the long term.
- **Promoting economic efficiency**
  - Bilateral contracts may improve short-term economic efficiency since generators will tend to bid at short-term marginal costs for any volumes up to the level of their obligations under bilateral contracts.

[35] In this context, it is important to clearly differentiate between the term ‘peaking plants’ from a daily operational and long-term planning perspective. In practice, the term ‘peaking plants’ is often used to describe those plants that are used to provide additional power during peak hours on a daily basis. Conversely, reliability also requires additional generation capacities that may only be required under very circumstances of the highest peak load observed over a time horizon of several years. Whilst the former group may still be able to earn their fixed costs over a large number of operating hours, average annual operating hours for the latter group will converge to zero.

- For similar reasons, bilateral contracts will incentivise generators to ensure the availability of their capacities whenever market prices are likely to be above their short-term marginal costs.

- In contrast, long-term contracts may impact long-term efficiency as they create a disadvantage for new entrants who will only be able to sell that part of demand, which is not already covered by long-term contracts, and/or when market prices are below the variable costs of generators holding long-term contracts.

- **Compatibility with other elements of market design**

    - Bilateral contracts represent a key component of liberalised electricity markets such that can be believed to be fully compatible with the overall market design.

- **Feasibility and costs of implementation**

    - Being a common feature of most liberalised electricity markets, we do not see any problems related to feasibility.

3.5 Demand-Side Measures

3.5.1 Short-Term Pricing

Demand-side measures are characterized by supplying reliability to the network from the customer side either by actively offering interruptible load as operating reserve on the market or by simply reacting to time varying prices. Due to the very demanding controlling and settlement process, this kind of demand-side measures is most-often restricted to large wholesale customers or retailers. However, recent developments in smart metering systems are expected to enable more small customers to provide the network with some degree of reliability.

Demand-side measures can take a number of different forms and can exist within a number of different market forms. However, there are a number of prerequisites that must be in place to enable or facilitate demand-side measures;

- There must be adequate metering to allow the demand to be measured and for any dynamic response to be recognized and quantified. Metering at a customer's premises will allow that customer to benefit from its own controllable demand management, either within the energy market environment, or under a demand reduction arrangement with the System Operator, for reserve purposes. If there is metering at a zonal level, there may be opportunities for a retailer, possibly in conjunction with a Distribution Network Operator, to offer customer discounts in return for some form of block teleswitching, or tariff based demand management, regime.

- Market mechanisms should be able to recognize and accommodate the demand elasticity. This ensures that any demand action will feed back into pricing, to ensure that economic efficiency does not deteriorate, as a consequence of demand elasticity;

- Prices must be dynamic and available in adequate timecales to incentivise demand response. Where the demand response is to be dictated by price, that price must be reflected through the market to the customer, or retailer, or SO as the case may be to ensure that the response is provided to greatest economic efficiency; and

- Retailers must be incentivized to encourage and accommodate demand reductions at customer premises. This will be the case if there is competition in electricity retailing, although some regulatory incentives may act as a surrogate for this.

If the above are in place, a number of potential arrangements can be contemplated to improve price-responsiveness:

- **Time-differentiated pricing**: In practice we see for household customers that traditionally a rather static approach is used with a simple two-tariffs-system only distinguishing base and peak periods (night and day). With traditional electromagnetic meters, this requires two separate meters. More advanced electronic meters are able to distinguish between more than two periods, e.g. using also a separate tariff for the shoulder period. In such cases the tariff per kWh may be lower in off-peak periods to incentivise customers to shift load into these periods and thus providing higher load in off-peak periods which allows for a more efficient power plant operation and also decreasing demand in peak periods, thus saving on expensive peak load generation. Such tariffs are relatively easy to handle, as consumed units for the specified periods are simply added up and collected via normal annual meter reading.

- **Use of indexed prices**: A more dynamic possibility to incentivise customers to react to price changes on the electricity market would be the usage of index-based tariffs. Index-based tariffs e.g. founded on spot market prices could be used on monthly basis and thus represent more mid-term price tendencies while at the same time isolating customers against day-to-day price volatilities. As traditional meter reading would be far too expensive on a monthly basis, such tariffs can only be used in connection with automatic meter reading, i.e. using electronic meters which can transfer meter data automatically to the central billing database. Moreover index-based tariffs can still be combined with static time-variable tariffs as stated above. One of the most essential tasks with such kind of tariffs to achieve significant consumer reaction is the transparent and prompt information of customers of their energy consumption and the currently valid price.

Recent developments in the field of smart metering enable not only remote meter reading but also communication of prices to the consumer. Theoretically smart metering even enables real-time pricing[36] (with household equipment automatically controlled by price signals). Whilst in practice real-time pricing for domestic consumers is still some future vision, for large consumers such real-time tariffs are already common practice, as these customers are typically fewer and with a higher turnover the effort is justified.

- **Critical Peak Pricing** – One of the potential developments with the roll out of smart meters is that retailers will offer critical peak pricing tariffs to residential customers. This will allow retailers to provide price signals to customers that will reflect when wholesale energy purchase prices or capacity prices are high giving customers the opportunity to reduce their consumption. These price signals could be done day ahead giving customers the opportunity to remove or reduce consumption on interruptible loads such as air conditioners. With sufficient numbers of these customers it should be possible for retailers to accurately predict some level of demand response and use this as a tool to reduce their forecast demand or potentially to bid into some forms of capacity markets

3.5.1.1 Qualitative Assessment

Using the four main criteria defined in section 3.1 above, the following points seem worth mentioning:

- **Security of supply**
    - Enabling price elasticity of demand by giving price signals to energy consumers will lead to a reduction of peak load, thus the reserve margin on the generation side and generation adequacy will be increased. The effectiveness of price signals is largely determined by the promptness with which price signals reach the consumer. This indicates that real-time pricing would be the most effective mechanism, but as real-time prices are very complex to handle, index-based prices distinguished for at least base and peak periods provide a second-best solution.
- **Short- and long-term economic efficiency**
    - It can be assumed that peak prices reach at least short-run marginal costs (which would mean fuel costs), but often also reach long-run marginal costs of peak-load generation. If prices were only short-run marginal costs all the time, the effect of price signals on resource adequacy would probably not last, with peak capacity decreasing as well; and

[36] Although most often, real-time pricing is in fact based on day-ahead market prices.

- Real-time price signals reflecting marginal costs would be economically efficient as consumers would individually value the current price level against their costs of not-consuming a particular unit of power[37] and based on that would come to a decision whether to consume power or not. In this case the available power would be used by those who would give a higher value to their consumption.

- **Compatibility with other energy market features**

  - In terms of compatibility with other energy market features it is not expected to cause any problems with the short-term price signals.

- **Feasibility and costs of implementation**

  - As already mentioned, because of the costs and effort connected with real-time pricing it is only used for large consumers. Nevertheless, technological development may pave the way for more sophisticated tariff designs for domestic customers.

3.5.1.2 Experience from Practice

In the winter 2002/ 2003 the Nord Pool spot market experienced extremely high price spikes, caused by a drier-than-expected winter in Norway. In previous years, melting snow had filled the Norwegian water reservoirs in spring/summer 2002, leading to extensive exports of electricity to neighbouring countries. However, the positive situation changed during the autumn when rainfalls failed to appear and the water reservoirs turned out to be insufficient to repeat the seasonal moderate up-and down-cycle of spot prices of former years. More precisely, reservoirs levels in Norway went down below 50% compared to an average level of some 70%. In addition to the Norwegian issues, the water reservoir levels in Sweden fell below the preceding-10-year minimum level.

The consequences on the common Nordic market were dramatic, with spot market prices reaching peaks of 8 times the average of former years. Moreover, large differences in water availability between “water-poor” Southern and “water-rich” Northern Norway caused a further temporary split-up of the Norwegian market areas, resulting in high price differences and bottlenecks. This development was anxiously monitored and discussed by market participants. Consumers mainly argued in favour of state intervention, while the regional system operators asked to rely on market forces to overcome the situation.

[37] This could also be called value of lost load (VoLL), though the VoLL is normally used (and calculated) on an overall level. This particular case refers to the individual VoLL of a particular consumer; this VoLL can’t be calculated exogenously.

The situation finally normalised in 2003 due to a variety of market-based counteractive measures that were taken. In addition to the activation of old, partially mothballed plants and increased imports there was two notable voluntary types of demand response:

- Large consumers responded by cutting the production from their processes, which reduced their consumption, allowing them to re-sell power at high prices; and
- Small consumers with indexed power prices reduced consumption, temporarily by up to 10%.

As a result of these measures and reactions, the Nordic electricity market successfully managed the crisis, until reservoir levels returned to normal levels in the spring of 2003. However, it became clear that the significant contribution by both large and small consumers was decisive in avoiding major brownouts or an entire collapse of the market arrangements as experienced two years earlier in the California electricity crisis of 2000/2001. Nevertheless, even the Californian crisis highlighted the potential impact of demand response, albeit only in response to extreme price signals.

However, both cases also show that, whilst there does exist some demand elasticity, it may often be limited to extreme prices, which may endanger the stability of the overall market arrangements. Although the period of extreme prices in the Nordic region did not result in the abandonment of the market as in California, it nevertheless triggered a serious discussion which might have had a similar result if the problems had persisted.

3.5.2 Provision of Operating Reserves by Interruptible Customers

3.5.2.1 Main Characteristics and Application in Practice

Instead of trusting either domestic or bulk consumers to react to price signals and thus reduce electricity demand in peak-load periods, demand-side reaction can also be gained from integrating customers into the markets for operating reserve. As discussed in the previous section this would lead to customers shedding their load if the price (assuming it is a real-time price) they would have to pay for consuming electricity exceeded the costs associated with not consuming. In the case of large industrial customers this can be assumed as being the same as the costs of not producing their product.

If consumers are able to take part in the markets for operating reserves they would shed load if prices on the operating reserve market would exceed their costs of not consuming electricity. Traditionally the operating reserves market is a market for powers producers offering their capacity, whereas interruptible contracts were very common between large consumers and energy suppliers. In the last years large consumers with interruptible load (e.g. electrolysis) which can be interrupted easily, started to offer their interruptible load as positive reserve on operating reserve markets. Because of the complexity and the prerequisites to be fulfilled, this is feasible for only a few very large customers, as interruptible load must be bid into the market and be capable of fast and reliable response.

3.5.2.2 Detailed Description

- Interruptible demand for operating reserve
    - Directly offering interruptible load on the operating reserve market is only possible for a few large consumers. These would preferably have large proportions of their load that can be reduced, as a consumer is unlikely to offer his whole load as interruptible but instead to reduce/remove a particular production facility which can be shut off for several hours without harm. This is only possible in restricted circumstances, as it is of no benefit if damage occurs which goes beyond the revenue earned on the operating reserves market. It is also an important prerequisite that power is shut-down fast, in the best case automatically. To encourage more and smaller electricity consumers to offer their interruptible load on the operating reserves market, market rules would need to be changed to account for the particular operating constraints of every party, e.g. regarding the amount of capacity offered, the lead time or duration of the interruption, this is likely to be a complex enterprise.
- Retailer demand management/virtual reserve units
    - Most processes which can be switched of easily, at least for a few hours, are too small to be offered individually on the operating reserves market. In this scenario, enabled by the development in the information and communication technology during the last decade, it is possible for electricity retailers to bundle the interruptible load of their customer into a portfolio. The retailer would need to offer interruptible contracts, install the necessary equipment and offer the bundled capacity on the operating reserves market, but would potentially profit from a more balanced portfolio. Taking into account the development in the field of smart metering and home automation it may be possible to bundle interruptible load of domestic consumers (e.g. freezers and fridges) for the operating reserve market.

3.5.2.3 Qualitative Assessment

- Security of supply
    - Resource adequacy would be directly enhanced as installation of expensive peak-load capacity can be avoided with more flexible load willing to shut down when a certain price is exceeded

- Short- and long-term economic efficiency
  - It would be economically efficient for consumers to reduce consumption if the costs for consuming electricity exceed the costs for not-consuming, assuming that costs of consumption would reflect marginal costs of supply. When bidding the interruptible load into the operating reserves market, the prices paid should reflect the opportunistic costs of consuming the electricity. It can therefore be assumed, that the prices on the operating reserves market will at least reach short-run marginal costs of peak generation.
- Compatibility with other energy market features
  - There appears to be no problem in terms of compatibility with other energy market features.
- Feasibility and costs of implementation
  - Including interruptible load into the operating reserves markets can be relatively straightforward for large industrial customers where the supporting systems and processes are manageable. The main costs are associated with setting up the necessary control and communication equipment and integrating the operating constraints of the large demand side consumers into the market model. Applying this model to a large number of smaller consumers is likely to be a much more complex task with higher costs of implementation.

3.5.2.4 Experience from Practice

The participation of interruptible customers may provide for an important increase in the availability of operating reserves. In Norway, the system operator has been able to procure a significant share of its total reserve requirements from consumers since the year 2000. Similarly, interruptible load provides for considerable amounts of reserves in both Sweden and Finland. However, one has to take into account the large share of energy-intensive industry in all three countries as well as the wide-spread use of electric heating in Norway, which generally makes it easier to procure short-term reserves from load. Nevertheless, all three system operators have taken specific steps to address consumers and make it attractive to them to offer the corresponding capacities to the system.

In addition, positive experiences have also been made by other system operators, including PJM (see section3.1). Similarly, the Belgian TSO has been able to procure a sizeable share of its requirements for operating reserves from interruptible load, reportedly for a lower price than for similar capacities being available from generating units.

4. International Examples

4.1 Introduction

To provide examples of the application of each of these alternative forms of energy market design KEMA provides an overview of their application in the following markets:

1) PJM,

2) New York,

3) Western Australia,

4) Great Britain (BETTA),

5) Irish SEM, and

6) Nordic market (Nord Pool).

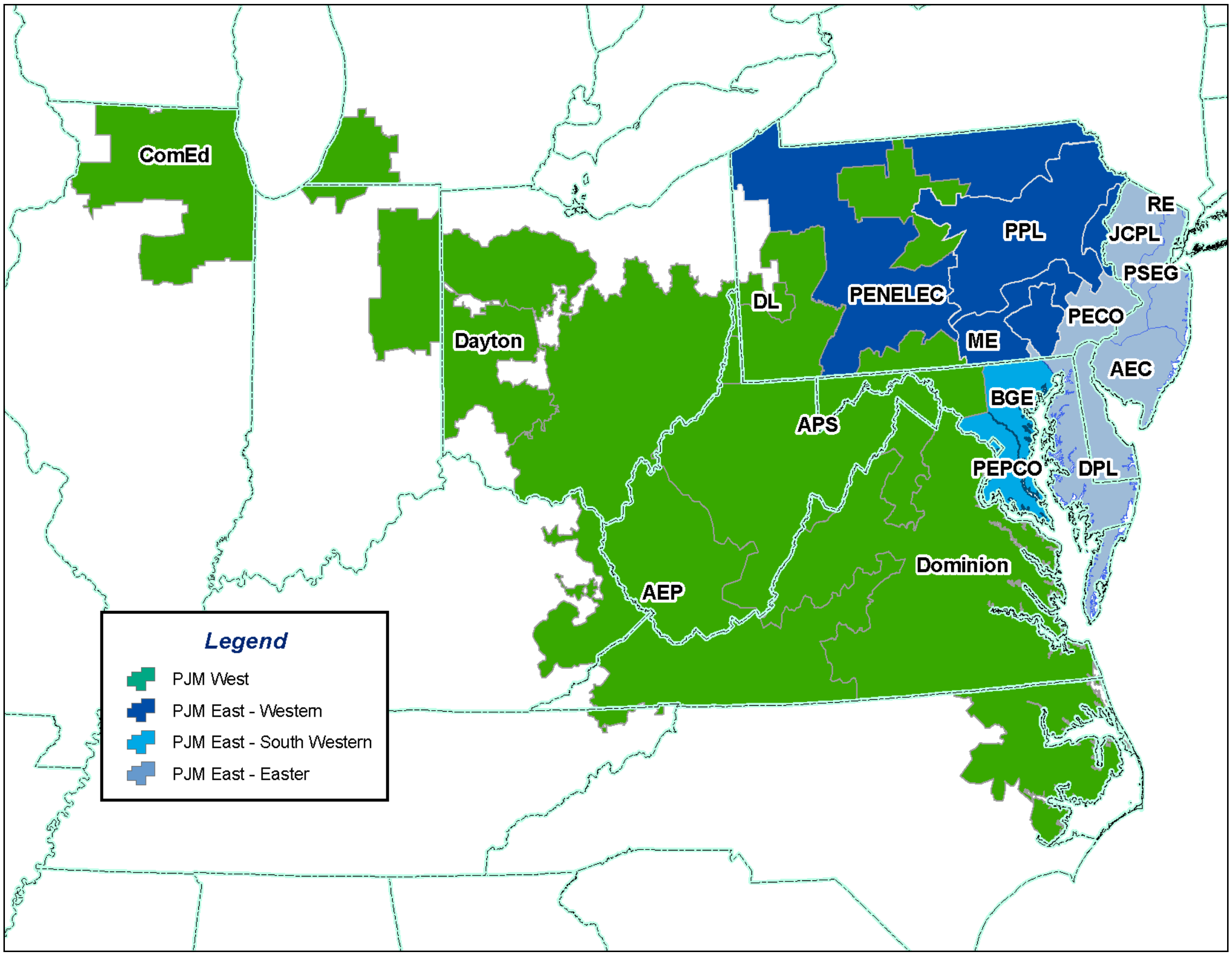
Each of these international markets is examined under a consistent framework in the following Sections 3.2-3.7.

4.2 PJM

4.2.1 Market Context

PJM Interconnection (PJM) is a Regional Transmission Organization (RTO) that serves a 168,500-square-mile control area. PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The PJM service area is shown in Figure 6. This service area is about 1,400 km east to west and 800 km north to south.

Figure 6: PJM Service Area



PJM provides the eight functions of an RTO:

1. Tariff administration and design;
2. Congestion management;
3. Parallel path flow;
4. Ancillary services;
5. OASIS, Total Transmission Capability (TTC) and Available Transmission Capability (ATC);
6. Market monitoring;
7. Transmission planning and expansion; and
8. Interregional coordination.

PJM's members, totalling more than 500, include power generators, transmission owners, electricity distributors, power marketers and large consumers. The company is headquartered in Valley Forge, Pa.

PJM's staff monitor the high-voltage transmission grid 24 hours a day, seven days a week. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions.

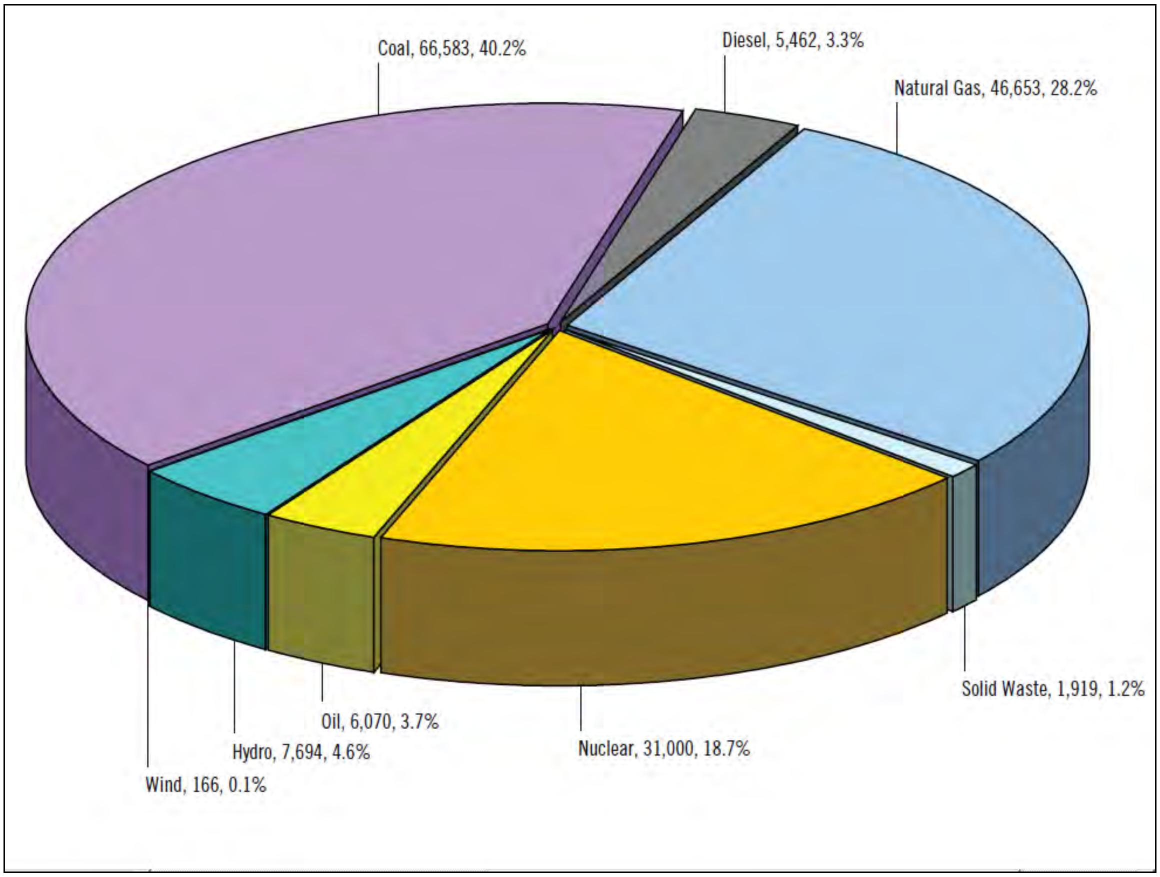
The company coordinates the continuous buying, selling and delivery of wholesale electricity through robust, open and competitive spot markets. In operating the markets, PJM balances the needs of suppliers, wholesale customers and other market participants and continuously monitors market behaviour.

Table 2: PJM Interconnection at a Glance

Membership	
Total (voting)	556 (351)
Transmission owners	58 (15)
Electric distributors	42 (35)
End users	26 (14)
Generation owners	121 (62)
Other suppliers	293 (225)
Generating capacity	165,000 MW
Number of generating units	1,279
Peak demand	145,000 MW
Miles of transmission lines	>56,000
Substations	>6,000
Gigawatt-hours of annual energy	760,000
Annual billings	$34.3 billion
States served	13 + D.C.
Square miles	>168,000
Population	51 million

The generating capacity in the PJM area is dominated by coal (40.2%) and nuclear (18.7%) as can be seen in Figure 7.

Figure 7: PJM Installed Generating Capacity by Fuel Source



4.2.2 Overall Market Design

The basic overall market design of PJM is a bilateral energy system with PJM operating a balancing energy market. PJM operates four specific markets—energy, capacity, financial transmission rights, and ancillary services. These four markets are summarized as follows:

1. **Energy Market**—PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants and monitors market activities to ensure open, fair and equitable access.

   PJM's Energy Market operates much like a stock exchange, with market participants establishing a price for electricity by matching supply and demand. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In this case more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price (LMP) is higher in those locations.

The Energy Market consists of Day-Ahead and Real-Time markets. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions and are published on the PJM Web site. PJM settles transactions hourly and issues invoices to market participants monthly.

2. **Capacity Market**—To ensure the future availability of the generating capacity and other resources that will be needed to keep the regional power grid operating reliably for consumers, PJM developed a new method of pricing capacity called the Reliability Pricing Model (RPM). The new capacity-market approach was implemented in 2007.

   Capacity represents the need to have adequate generating resources – “iron in the ground” – to ensure that the demand for electricity can be met at all times. In PJM’s case that means that a utility or other electricity supplier is required to have the resources to meet its customers’ demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract, or with capacity obtained through PJM’s capacity-market auctions.

   The new RPM system includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – not just generating plants, but demand response and transmission facilities as well.

   The essential elements of the RPM capacity market are procurement of capacity three years before it is needed through a competitive auction; a phase-in of locational pricing for capacity that varies to reflect limitations on the transmission system’s ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM; and a variable resource requirement to help set the price for capacity.

   The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or will provide through bilateral contracts.

3. **Financial Transmission Rights Market**—PJM also operates a market for financial transmission rights (FTRs) to assist market participants in hedging price risk when delivering energy on the grid.

   FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly energy-price differences across a transmission path in the Day-Ahead Market.

   The FTRs provide a hedging mechanism that can be traded separately from the transmission service. This gives all market participants the ability to gain price certainty when delivering energy across PJM.

   Market participants can obtain FTRs in three ways:

   - They can bid for them in PJM's annual auction, in which FTRs for the entire transmission capability of the system are available;
   - They can bid for them in the monthly auctions at which leftover FTRs are sold; and
   - They can buy them in the secondary market in a transaction with another market participant.

   Market participants can manage their FTR portfolios by using the eFTR tool. Participants use eFTR to post their FTRs for bilateral trading as well as to participate in the scheduled monthly FTR auctions.

4. **Ancillary Services Market**—Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers.

   PJM currently operates two markets for ancillary services – regulation and synchronized reserve.

   The regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired frequency. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party or by buying it on the regulation market.

   The synchronized reserve service supplies electricity if the grid has an unexpected need for more power at short notice. The power output of generating units supplying synchronized reserve can be increased quickly to supply the needed energy to balance supply and demand. Load Serving Entities (LSEs) can meet their obligation to provide synchronized reserve to the grid by using their own generation, by purchasing the required synchronized reserve under contract with another party or by buying it on the synchronized reserve market.

4.2.3 Specific Mechanisms aimed at Supporting Reliability and Security

4.2.3.1 Overview

PJM addresses reliability in both generation and transmission. In regard to generation reliability there is a decades-old capacity margin requirement that all LSEs must secure. This is supplemented by the capacity market.

PJM determines the Capacity Requirement for the entire PJM footprint to achieve this reliability objective assuming sufficient network transfer capability will exist. The energy from generating facilities that are ultimately committed to meet this capacity requirement must be deliverable to wherever they are needed within PJM in a capacity emergency. Therefore, there must be sufficient transmission network transfer capability within PJM. PJM determines sufficiency of network transfer capability through a series of deliverability tests.

In transmission there are three levels of transmission studies and requirements. The first is defined by PJM as a load deliverability test. The second is a generation deliverability test. And the third is the more conventional system-wide contingency analysis.

These methods, or both generation and transmission, extend practices established by PJM by the 1960s but adjusted to reflect changes introduced by markets since the 1990s.

4.2.3.2 Capacity Market – Determining the Generating Capacity Margin Requirement

Following PJM's transition to a market format in the mid-1990s, they experienced a generation construction boom, resulting in region-wide capacity surpluses compared to the ISOs' resource adequacy criteria. The regional surplus depressed market prices for energy and operating reserves, placing generation margins, and hence contributions to fixed costs to near zero for peaking units. This left most generators with insufficient revenues to cover fixed costs. This problem affected both peaking units and intermediate and base load units. For example, PJM estimated that over the 1999-2004 period combustion turbines would have earned only about half of the revenues needed to recover fixed costs, while intermediate and base load units would have recovered about two thirds or less of the revenues needed to cover their fixed costs.[38]

The result was a substantial fall off in for new capacity proposals, only about 111 MW were added in 2003-2004 with another 920 MW under construction. There was almost no new capacity proposed for the

38. Revenue recovery form margins in the PJM energy markets.

region. At the same time, there has been a substantial increase in the number of retirements. Without significant capacity additions and/or transmission upgrades into the area, Eastern PJM would be unable to meet reliability requirements as early as 2008.

PJM modified its approach to integrated planning by linking a long-run planning approach for transmission expansion with a long-run procurement approach for all infrastructure. The intent was to allow alternative investments in generation and transmission, as well as demand-side response, to compete in the same ISO-administered auction. PJM believed that short-run prices alone would not provide sufficient encouragement or support for long-run investments. The PJM approach features a series of forward auctions for products to be delivered as much as four years in the future, based on the belief that without such forward obligations, the appropriate investments would not be made.

The pool requirements are established to ensure sufficient installed generating capacity to meet the forecast load plus reserves adequate to provide for the unavailability of capacity resources, load forecasting uncertainty, and unplanned and maintenance outages. The pool requirement is determined for a specified planning period to establish the level of capacity resources (and active load management) that will provide an acceptable level of reliability consistent with the reliability principles and standards.

The pool requirement is determined using three equations:

$$PR = \frac{UCR}{(FAP - FALC)} 100$$

Where:

PR is	Pool requirement
UCR is	Unforced capacity requirement
FAP is	Forecast weather-normalized 50/50 probability peak load prior to active load management being invoked
FALC is	forecast active load management

$$UCR = ICR\left(1 - EFOR_D\right)$$

Where

ICR is	Installed capacity requirement
$EFOR_D$ is	Regional equivalent demand forced outage rate

$$EFOR_D\,(\%) = \frac{\left(f_f * FOH + f_p * EFPOH\right)}{\left(SH + f_f * FOH\right)} * 100$$

Where

f_f is	Full outage factor
f_p is	Partial outage factor
FOH	Full forced outage hours
EFPOH	Equivalent forced partial outage hours
SH	Service hours

$$ICR = (FAP - FALC)(1 + IRM)$$

Where

IRM is	Installed reserve margin approved by the PJM Board

Each LSE must acquire sufficient capacity to meet its load plus installed reserve margin.

4.2.3.3 Capacity Market – The Reliability Pricing Model

As discussed above, the general requirements and obligations concerning PJM resource adequacy are defined in the reliability assurance agreement among LSEs in the PJM Region. PJM is responsible for calculating the amount of generating capacity required to meet the defined reliability criteria. The final reserve margin value is then the basis for defining the RTO reliability requirement for use in the reliability pricing model (RPM) base residual auction conducted three years prior to the delivery year. The total capacity procured in the auction is allocated as a capacity obligation to all LSEs within PJM. Each LSE is charged a Locational Reliability Charge associated with its capacity obligation.

The RPM is the PJM resource adequacy construct that ensures that adequate capacity resources, including planned and existing generation resources, planned and existing demand resources, and interruptible load for reliability (ILR) will be made available to provide reliable service to loads within the PJM Region.

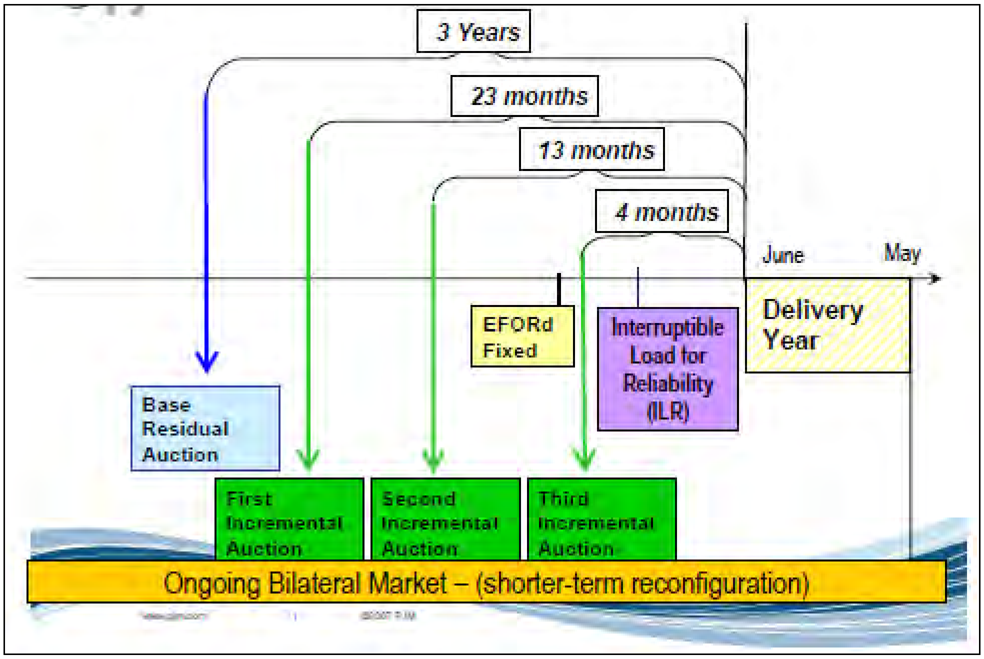
The purpose of the RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM is also designed to add stability and a locational nature to the pricing signal. The RPM is a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction (BRA), Incremental Auctions (IA) and a Bilateral Market.:

Base Residual Auction - The BRA is held during the month of May three (3) years prior to the start of the Delivery Year. The BRA allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through a Locational Reliability Charge.

- *Incremental Auctions* – Up to three Incremental Auctions are conducted after the BRA to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
    - *The First and Third Incremental Auctions* are conducted to allow for an incremental procurement of resource commitments when there is a decrease in the value of committed resources as a result of a resource cancellation, delay, derating, EFORd increase, or a decrease in the nominated value of a Planned Demand Resource. The cost of procurement in these Auctions is allocated to the resource providers that caused the need for additional resources to be procured.
    - *The Second Incremental Auction* is conducted to allow for an incremental procurement of resource commitments when there is an increase in the region's unforced capacity obligation as a result of a load forecast increase. The cost of procurement in the Second Incremental Auction is allocated to LSEs through a Locational Reliability Charge.
- *The Bilateral Market* – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined through the BRA and Second Incremental Auction. The bilateral market is facilitated through the eRPM system.

The timing of the four auctions is shown in Figure 8

Figure 8: Timing of RPM Auctions



4.2.3.4 Transmission Planning Conventional Contingency Test

Overall transmission planning at PJM is handled through the Regional Transmission Expansion Plan (RTEP). In developing these plans the system is modelled with a 50/50 load forecast and all generation dispatched at the same level in proportion to their maximum capability so that load and generation is in balance. The system is then subject to the various contingencies in the regional and national reliability standards. These tests are made after the two deliverability tests described below are made. In practice, no new contingency violations are found that have not already been identified in the deliverability tests.

4.2.3.5 Transmission Planning Load Deliverability Test

The Load Deliverability Test tests the delivery of energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area experiencing a capacity deficiency. This test is the most common deliverability test and has been utilized within PJM for some time. It is often discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy can be delivered to each PJM load area from the aggregate of capacity resources available to PJM (regardless of ownership.) These tests address reliability only and do not address the economic performance of the system.

4.2.3.6 Transmission Planning Generation Deliverability Test

The Generation Delivery Test is applied to the generating capacity of the entire PJM footprint. The acceptable Loss of Load Expectation (LOLE) is based on load exceeding available capacity, on average, during only one occurrence in ten years (1/10). This concept of deliverability coincides with the assumptions inherent in the determination of the PJM Installed Reserve Margin (IRM), i.e. the total amount of installed capacity necessary to be at the disposal of the PJM operator to ensure delivery of energy to load consistent with an LOLE of 1/10. The determination of the IRM is based on the assumption that the delivery of energy from the aggregate of available capacity resources to load within the PJM footprint will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout PJM and the strength of the Transmission System to deliver energy to portions of PJM experiencing capacity deficiencies.

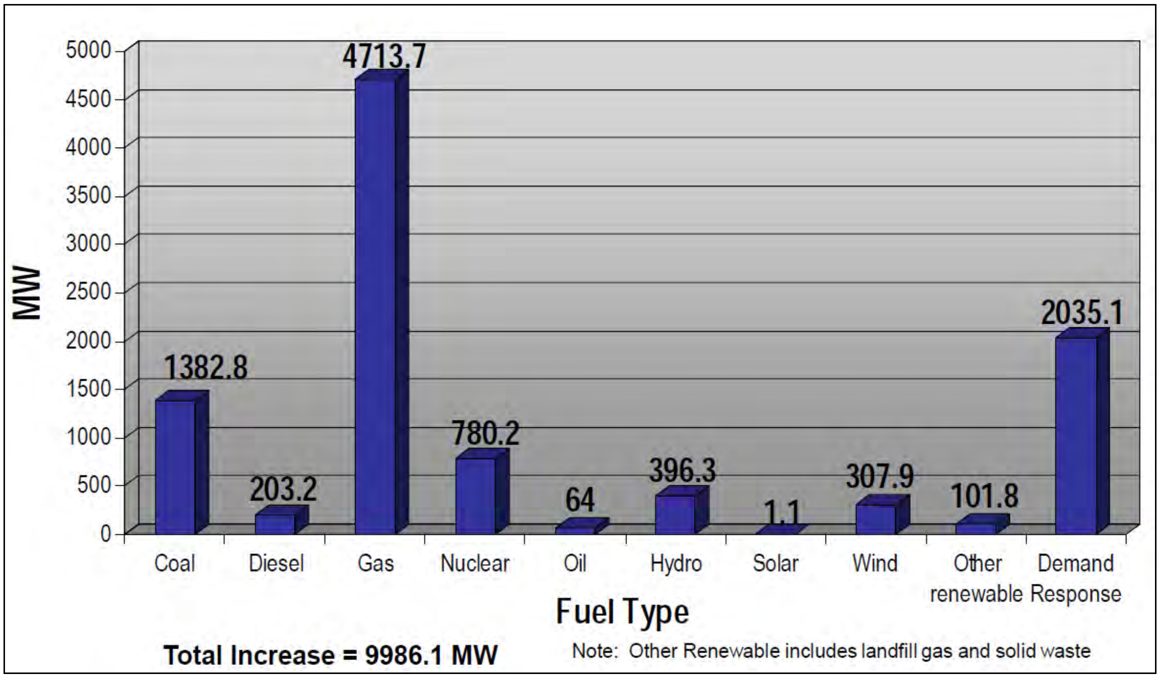
The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modelled.

4.2.4 Experiences to Date

After an extensive stakeholder process that developed the RPM capacity market over a period of years, the new capacity auction was implemented in 2004. The May 2008 annual auction for capacity for the operating year of 2011-2012 showed results that signalled significant changes in how capacity is procured. More than 4,200 MW cleared the May auction with more than 1,000 MW of base load. A record amount of demand-side resources was bid into auction, and the first solar generating plant was bid and cleared in the auction. PJM is working through the stakeholder process to bring energy efficiency resources into the RPM Capacity Market with the promise of even greater demand-side participation in the RPM in future auctions.

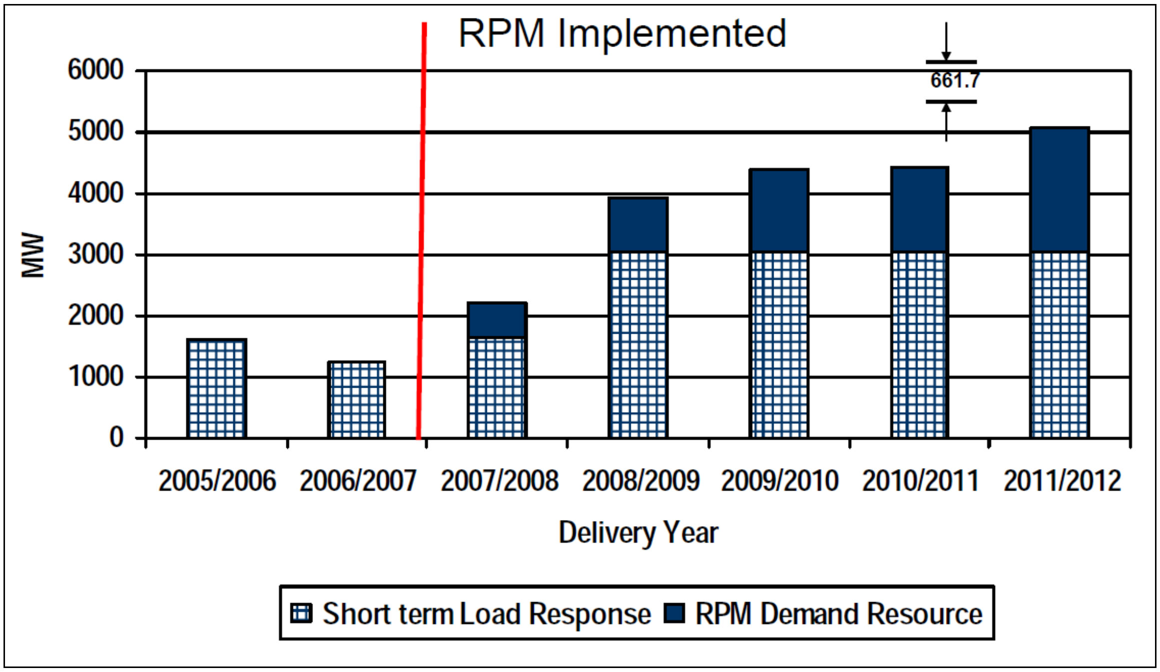
The results of the first five RPM auctions, illustrated in Figure 9, have delivered investments to supply 9,986 MW of new resources, including a base-load coal plant, over 800 MW of renewable resources, and over 2,000 MW of new Demand Response resources.

Figure 9: Capacity Resource Additions in the First 5 RPM Auctions



Additionally, the trend of an increase in overall demand response activity across the five RPM auctions has been significant as illustrated in Figure 10. Prior to RPM, PJM experienced a decline in customer willingness to provide curtailment during system emergency conditions which required PJM to seek more generation resources to supply PJM's reliability requirements. With the implementation of RPM, total load response in the capacity market has increased by over 3,500 MW which is the equivalent of displacing the need to install 3 to 4 large base load generation plants.

Figure 10: Demand response trend resulting from RPM implementation



4.3 New York

4.3.1 Market Context

The New York Independent System Operator (NYISO) manages New York's electricity transmission grid a 10,775-mile network of high-voltage lines that carry electricity throughout the state. The NYISO also oversees wholesale electricity markets where more than $50 billion has been transacted since 1999.

The NYISO is a not-for-profit corporation regulated by the Federal Energy Regulatory Commission. It is governed by a 10-member Board of Directors whose members come from the power industry, environmental organizations, the fields of finance, academia, technology and communications. The members of the Board, as well as all employees, are independent; they have no business, financial, operating or other direct relationship to any Market Participant or stakeholder.

Under a unique form of shared governance, representatives from stakeholder groups discuss, debate and vote on issues directly affecting the NYISO's operations, reliability and markets. The three committees – Management, Operating and Business Issues – are supported by several subcommittees, which are made up of individuals from five major sectors of the marketplace: Transmission Owners, Generation Owners, Other Suppliers, End-Use Consumers, and Public Power and Environmental Parties.

The NYISO's predecessor was the New York Power Pool, a consortium of eight investor-owned utilities. Since Dec. 1, 1999, the NYISO has grown into a 400-person organization that is responsible for administering the market, allowing for open access to the transmission system, operating a reliable transmission system and serving as the authoritative source for all energy related matters in New York.

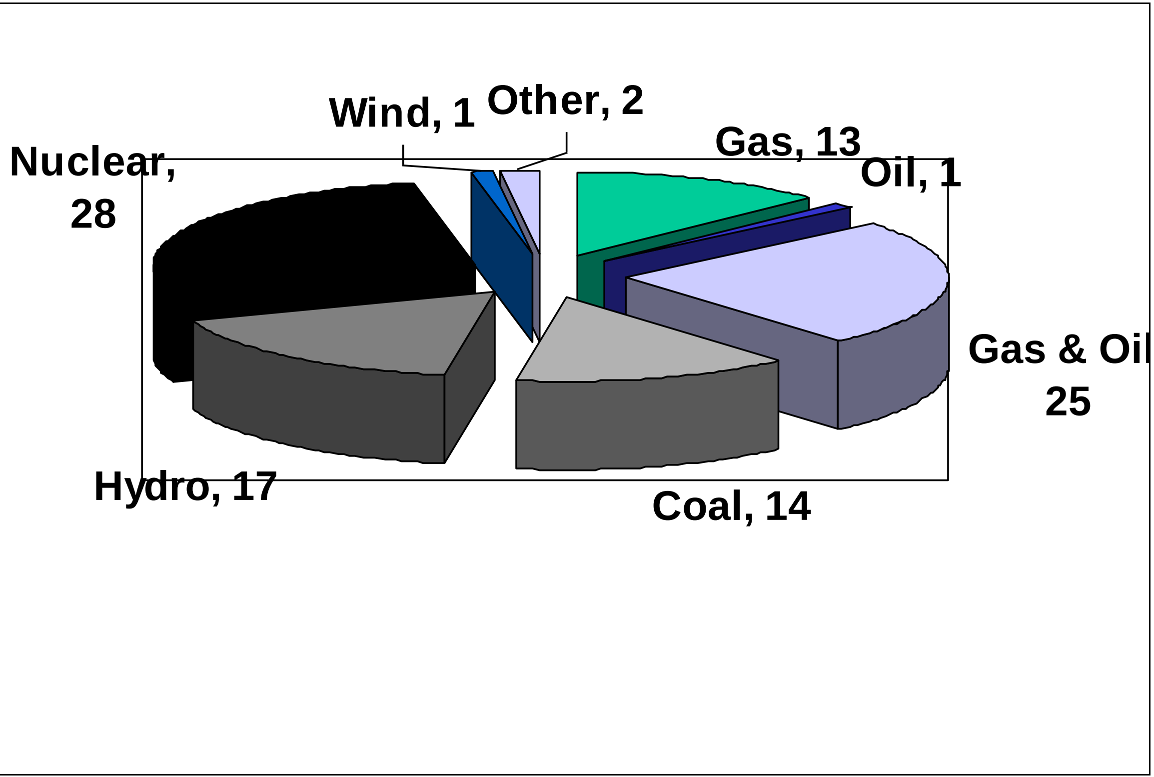
The NYISO offers a variety of market data and other important information to help those who buy and sell electricity in New York's energy markets make more informed trading decisions. This information should assist Market Participants in determining whether to invest in new technologies, reduce energy usage, or propose new power plants and transmission lines so New Yorkers have adequate supplies of electricity. An overview of the key elements of the market is shown in the table below.

Table 3: NYISO at a glance

Generating capacity	38,547 MW
Number of generating units	335
Peak demand	33,452 MW
Miles of transmission lines	10,775
Gigawatt-hours of annual energy	165,000
Annual Wholesale electricity market costs	$10,000,000,000
States served	1
Square miles	47,225
Population	19,500,000

The generating capacity in the NYISO is provided by a mixture of fuels with nuclear (28%) and natural gas (25%) being the most significant as can be seen in Figure 11.

Figure 11: NYISO Installed Generating Capacity (%) by Fuel Source



4.3.2 Overall Market Design

The basic overall market design of the NYISO is a bilateral energy system with NYISO operating a balancing energy market. The NYISO also operates six Ancillary Service markets: (1) Scheduling, System Control, and Dispatch; (2) Voltage Support; (3) Regulation and Frequency Response; (4) Energy Imbalance; (5) Operating Reserves; and (6) Black Start Capability.

The NYISO operates a two-settlement system—a day-ahead market and a real-time market. The day-ahead scheduling process consists of the following principal functions:

1. Assemble day-ahead transmission outages—updates total transfer capabilities, constraints and the security constrained dispatch model; post updated total transmission capability on the open access same time information system;

2. Produce New York ISO preliminary zonal load forecast—based on weather forecasts and the load forecast model; and

3. Perform security constrained unit commitment.

Approximately 90 minutes ahead of each hour, an evaluation takes place to ensure that the day-ahead schedules meet all of the reliability requirements. Each hour-ahead transaction is evaluated independently against the day-ahead transactions and generator bids. Any new firm transactions will be scheduled which could displace some of the day-ahead non-firm transactions. The results are then posted by 30 minutes before the hour as the schedule for the next hour.

In the real-time dispatch, the security-constrained dispatch uses bid curves of the generators to dispatch the system to meet the load while observing transmission constraints. Bid curves consist of a combination of incremental bid curves provided by generators bidding into the market and decremental bid curves provided by generators serving bilateral transactions.

4.3.3 Specific Mechanisms aimed at Supporting Reliability and Security

4.3.3.1 Overview

The NYISO's increasingly important planning function looks ahead to assess New York's electricity needs and evaluate the ability of planned new power facilities and other options to meet those needs. With the recent approval of the Federal Energy Regulatory Commission (FERC), the NYISO is about to embark on an expanded economic planning process starting in mid-2009. This planning process involves dozens of stakeholders, regulators, public officials, consumer representatives, and energy experts in order to receive vital information and input from a variety of viewpoints.

Each year the NYISO performs a Reliability Needs Assessment. The process was initially approved by the FERC in 2004. The process includes a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system for a 10-year planning horizon. The process has been highly successful in identifying needs and obtaining market-based solutions to meet those needs, and in lining up both transmission owners (TOs) and alternative regulated solutions to be called upon as a backstop only if market solutions are not forthcoming when needed.

4.3.3.2 Assuring resource (generation) adequacy

The NYISO uses an Unforced Capacity methodology to determine the amount of Capacity that each Resource is qualified to supply to the New York Control Area (NYCA), and to determine the amount of Capacity that Load Serving Entities (LSEs) must procure. The Unforced Capacity methodology estimates the probability that a Resource will be available to serve Load, taking into account, forced outages. Unforced Capacity is defined as: The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the NYISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Minimum Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Minimum Installed Capacity Requirement for which each LSE is responsible.[39]

The process includes these steps:

- The State Reliability Council sets the Installed Reserve Margin and the NYISO determines the minimum installed capacity requirement in accordance with the applicable criteria and standards.
- The NYISO converts the minimum installed capacity requirement into a minimum unforced capacity requirement.
- The NYISO assigns Minimum Unforced Capacity Requirements to LSEs.
- The NYISO determines the amount of Unforced Capacity that internal and external suppliers may supply.
- The NYISO conducts three types of Installed Capacity auctions: the Capability Period Auction, the Monthly Auction, and the ICAP Spot Market Auction.
- LSEs may procure adequate Unforced Capacity from suppliers to meet their requirements either with bilateral contracts or through NYISO-administered auctions.
- All LSEs that have not met their Unforced Capacity requirement must participate in the ICAP spot market auction.

The difference between ICAP and UCAP

ICAP (Installed Capacity) represents generating capacity that is physically on the ground and has a defined value determined by a valid test. Example - a generating unit with a face value of 100 MW but the test results show that the unit can only produce 98 MW. The NYISO will rate this unit at 98 MW for ICAP purposes.

UCAP (Unforced Capacity) represents the amount of ICAP that is actually available at any given time. It also is the unit used for buying and selling ICAP. UCAP is the percentage of ICAP available after a unit's forced outage rate is calculated. Performance data is submitted monthly for each generating unit. If a unit was unavailable due to a forced outage for 10% of the hours in a month, the forced outage rate would be 10% and therefore, only 90% of the ICAP would be available.

A rolling 12 month average of the monthly forced outage rate is used to determine the amount of ICAP that can be sold in units of UCAP. If the 12 month forced outage rate is 10%, the above unit would only be allowed to sell 88.2 MW (0.90 x 98 MW) of UCAP in the next monthly ICAP auction.

4.3.3.3 Assuring transmission adequacy

The NYISO conducts transmission system analyses to fulfill three separate purposes:

1. Determine transmission reliability Needs based on security criteria;
2. Calculate independent emergency transfer limits for all noted interfaces for the MARS resource adequacy model;[40] and

39. The term “Installed Capacity” describes the market as opposed to the product. For example, the NYISO administers “Installed Capacity auctions” where “Installed Capacity Suppliers” offer “Unforced Capacity” that LSEs will purchase to meet their “NYCA Minimum Installed Capacity Requirements.”
40. The primary tool for conducting the resource adequacy assessment is GE Energy’s Multi-Area Reliability Simulation program (MARS). MARS uses a Monte Carlo simulation to compute the reliability of a generation system comprised of any number of interconnected areas or zones.

3. Develop transfer limit nomograms and joint interface groupings for use in the mars resource adequacy model.

The transmission system analyses starts with a screening analysis, followed by a resource adequacy assessment. These steps are conducted in a sequential and iterative process to maintain internal consistency between the two steps.

Detailed assessments include power flow (steady state) and stability (dynamics) simulations focusing mainly on areas in the system identified in screening step. The four major types of analyses are:

1. Thermal contingency analysis
2. Steady-state Contingency Voltage Drop analysis
3. Voltage Collapse/Voltage Stability analysis
4. Transient (Angular) Stability analysis

The security criteria for transmission capability determination are based on a deterministic approach. The system must perform acceptably following facility outages resulting from a single event from the normal system condition; commonly referred to as a “single contingency” or from two simultaneous or overlapping facility outages; referred to as a “double contingency.” The system must also meet design criteria after a critical element has already been lost. This is often referred to as an N-1-1 assessment. All three requirements allow for limited system adjustments after the loss of the critical element, including load shedding both before and after the contingency that occurs after the critical element loss.

4.3.4 Experiences to Date

The capacity market was first established based upon a completely vertical demand curve. This vertical demand curve resulted in a number of problems, including large capacity price variations even when there were only small variations from the capacity target.

The design innovation of the NYISO capacity market design is in using a demand curve with a non-vertical slope—also referred to as a “downward sloping” demand curve. The downward sloping demand curve is designed to provide price stability, address market power concerns, and provide a more stable revenue stream for resources. Such a curve is illustrated in Figure 12 below.

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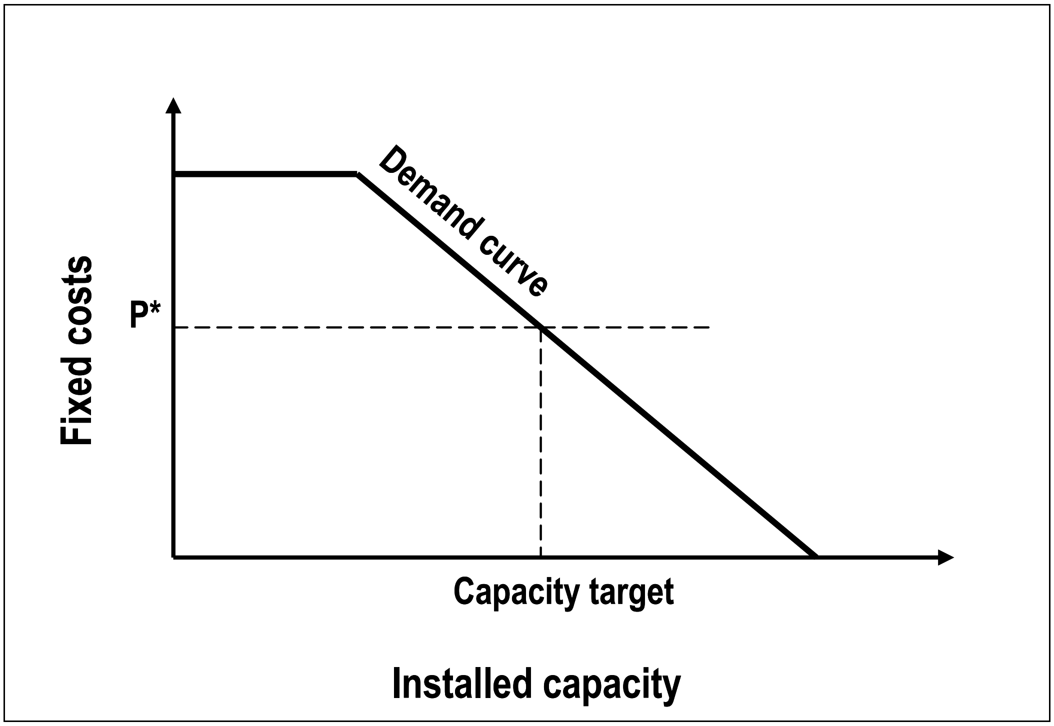
Figure 12: Illustration of a downward sloping demand curve



In the diagram above the vertical axis is fixed-cost recovery and the horizontal axis is amount of installed capacity. The horizontal line at P* is the annual carrying cost of a new simple-cycle combustion turbine generating unit. The capacity target is the minimum acceptable capacity level for reliability (e.g. 16% reserve margin). The price for providing the capacity target is P*. This price (P*) could be the normal cost of new entry of a generator in the market or the annualized fixed cost of a benchmark generator. The market would tend to provide the target capacity level because investment would be stimulated when actual capacity is below the capacity target.[41] Similarly, capacity is discouraged when actual capacity is above the capacity target. The capacity target is set to ensure reliability and the demand curve set to ensure a revenue stream of P* (normal fixed-cost recovery) when installed capacity equals the capacity target.

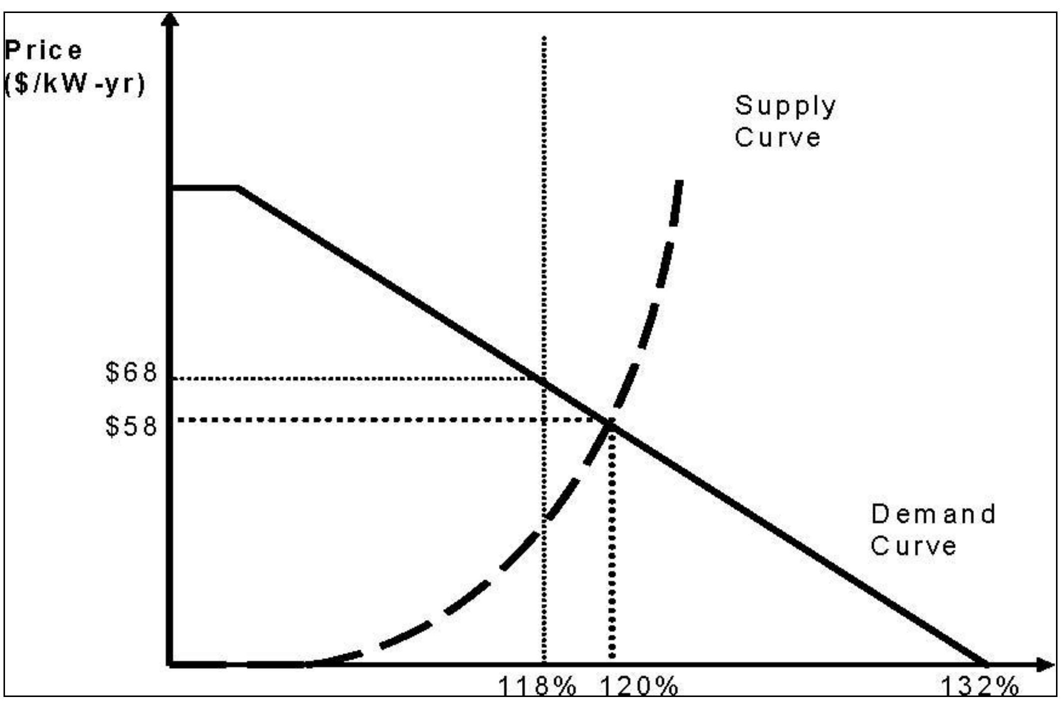
41. In such a case additional generation capacity is encouraged as long the revenue of new entry stays above P*, the fixed cost recovery point.

Payments to ICAP suppliers are intended to induce generation investments. New York has three ICAP areas based on different capacity availability conditions within the NY ISO control area: Long Island, New York City, and the remainder of New York State. A demand curve is determined for each zone.

The initial result of the ICAP market, using a vertical demand curve, was that prices were very high when capacity was even slightly below the target quantity, or prices went to zero when there was a capacity surplus. The results were extremely volatile; the capacity price was either extremely high or low. Given the "boom and bust" market pricing signal, developers were reluctant to finance new projects. The NYISO was concerned that new generation additions would not keep pace with growth in electricity demand within the state and that there would be capacity deficiencies.

In 2003 FERC approved the NYISO's demand curve filing. NYISO's downward sloping demand curve design was based on the estimated cost of a new peaking generator and the curve was set by the price of installed capacity. The curve is shown in Figure 13, below. The price falls for increments above the target (118 % of peak load) until it is priced at zero at 132% of peak load, and the curve goes to zero at different points in each of the three ICAP regions in the state.[42] The demand curve was phased-in over three years and was established by a process involving the NYISO, state utility commission and stakeholders.

Figure 13: Capacity demand curve (2003)



42. The 2009 target was set at 16.5% rather than the 18% shown in the figure.

The results have shown that the ICAP price and revenue streams for suppliers have stabilized.

A critical and attractive feature of the New York downward sloping demand curve approach is that it is designed to substantially reduce market power in the capacity market. The administratively set downward sloping demand curve is established and results in a reasonable price for capacity. In the pre-capacity demand curve approach, even a slight shortage of capacity could result in prices near the cap, providing incentives for physical withholding. Under the downward demand curve approach, small changes in the quantity of capacity result in much smaller changes in the price, reducing the reward for withholding.

Although the New York capacity market has had good reviews for stabilizing price and revenue streams some have expressed concerns with the New York demand curve. These concerns range from claims of exercise of market power in constrained zones to complaints that penalties against non-performing suppliers are not strong enough.

They claim the modified capacity market has resulted in large amounts being collected from customers, but still have not worked to stimulate new resources, even as the capacity reserve margin in New York is shrinking. The reserve margin was 18%, however, the state would soon violate this reliability standard. In 2007, the margin was reduced to 16.5%.

They attribute the problems to the failure of the market approach to induce new capacity additions. New plants were added by the publicly operated New York Power Authority and under contract with Con Edison (the LSE for New York City). It was assumed that the cost of capacity in 2006 would change with this addition of new resources, but it did not. Sellers in capacity markets may be able to raise the price paid to all through strategic withholding, which is done by offering a portion of the capacity at a price so high it is effectively withheld. It became apparent to some market participants that capacity had been withheld from the NYISO capacity market in 2006 to maintain high prices.

Some of the specific complaints raised by stakeholders include:[43]

- The NYISO consultant has drawn the ICAP demand curves with the intent of inducing development of considerably more capacity than is needed to meet minimum ICAP requirements, thereby causing a significant upward shift in the demand curves. This is contrary to the provision in the NYISO's Control Area Administration and Market Services Tariff ("Services Tariff"), which requires the NYISO to determine the cost of developing sufficient capacity to meet minimum capacity requirements.

43. *Comments on NYISO Staff's Proposed Installed Capacity Demand Curves for the 2008-09, 2009-10 and 2010-11 Capability Years*, submitted by Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, LIPA, New York Power Authority, New York State Electric & Gas Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation (the Transmission Owners), October 1, 2007.

- The proposed demand curves underestimate the energy and ancillary services revenues that would be earned by a new supplier because they are based on the assumption that there will be considerable amounts of excess capacity in the future, which is unreasonable and inconsistent with the Services Tariff. The proposed demand curves also overestimate the costs to be incurred by a new supplier by arbitrarily reducing the amortization periods used for power plant investments in the current demand curves.

- The demand curves are based on an inflation adjustment factor that assumes that the short-term increases in cost of power plant construction will continue in the future, which is inconsistent with reliable long-term data.

- The adjustment to account for seasonal differences in ICAP prices used in the demand curves is significantly larger than needed to offset the effect of those seasonal ICAP price differences.

- The proposed zero crossing point (the point at which the ICAP demand curves reach a price of zero) has not been supported by any analysis, despite the fact that the zero crossing point has a significant effect on the demand curves.

In response, the NYISO filed its *Report on Implementation of the New York Installed Capacity Demand Curves*, finding no market withholding or other dysfunction:

> "the performance of the market does not raise concerns about withholding in the overall NYCA or Long Island markets. The observed bidding behavior in New York City is consistent with expectations under the Commission-approved mitigation measures."

This dispute regarding the impact of the capacity market is ongoing.

4.4 Western Australia

4.4.1 Market Context

The principal electricity infrastructure in Western Australia is encapsulated within the South West Integrated System (SWIS). The SWIS extends from Kalbarri in the north to Albany in the south and to Kalgoorlie in the east of the state of Western Australia and includes the metropolitan area around Perth.

The network comprises some 6000km of transmission lines and 64,000km of distribution, with the main transmission circuits being at 330kV, 220kV, 132kV and 66kV and distribution circuits at 33kV, 22kV, 11kV, 6.6kV and 415V. The main base load centre of generation is near the coal mining facilities at Collie, some 200km south of Perth and the principal peaking plant is near the Dampier to Bunbury gas pipeline north of Perth. There is further generation at Kemerton, Kalgoorlie and Kwinana. There are no interconnections with any other networks and there are a number of constraints that prevail on the system, many being associated with voltage requirements (as well as resulting from thermal limits), reflecting the relatively long transmission/distribution circuits and the high usage of air-conditioning load. The following map identifies the geographical extent of the SWIS (and also identifies the other major network in Western Australia; the North Western Interconnected System.

Figure 14: Electricity Infrastructure Map – Western Australia

Generating capacity is comprised of some 65% gas-fired plant (of which about half is dual-fired, also able to burn fuel oils), 28% is coal fired, some 2% is oil fired and the remaining 5% is made up of renewable sources (principally wind, but also some land-fill gas and some solar). The peak demand occurs in the summer, typically in early March and is around 4GW, with annual growth of some 2.5%. The SWIS supports approximately 840,000 customers.

There are some 40 participants within the SWIS, including the Independent Market Operator and the Electricity Networks Corporation that acts as a system operator. The Electricity Generation Corporation is an incumbent generator that owns and operates 66% of the installed capacity and there are six Independent Power Producers (IPPs) that each own more than 1% of the installed capacity, the largest of these owns some 15% of the overall installed capacity. There is also of the order of 125MW of demand side management capability within the SWIS. The following charts summarize the generation mix within the SWIS.

Figure 15: Capacity Credits by Fuel type (Source: IMOWA - Statement of Opportunities, 2008)

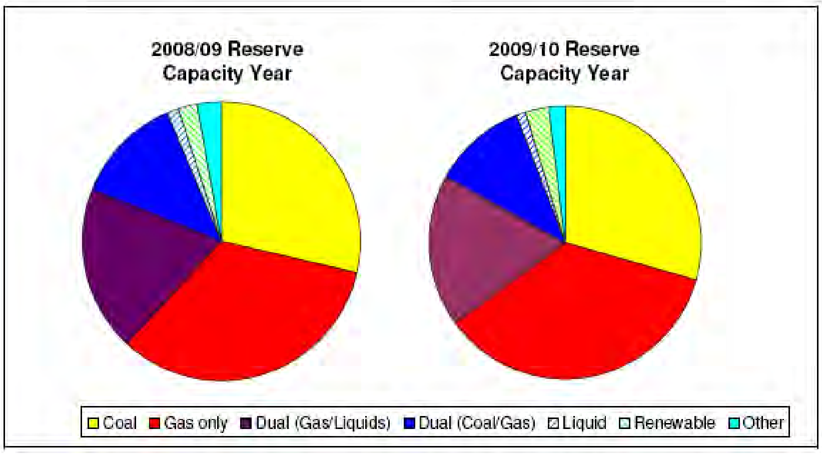
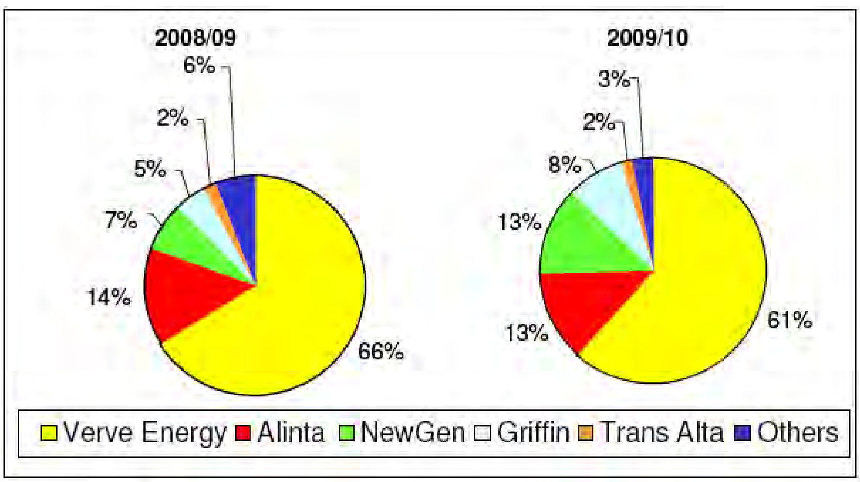


Figure 16: Capacity Credits by Market Participant (Source: IMOWA - Statement of Opportunities, 2008)



The IMO has been operating the capacity related arrangements in the SWIS since 2004 and the full SWIS market rules have been in operation since 2006.

4.4.2 Overall Market Design

The market is administered by an Independent Market Operator (IMO) with Network Operators providing transmission and distribution networks. Trading principally takes place between Market Generators and Market Customers; participants that provide energy onto the SWIS and those that take energy from the SWIS, respectively.

In addition there are three incumbents within the SWIS:

- The Electricity Networks Corporation (Western Power) who own and operate much of the network within the SWIS and also act as the system operator, responsible for real-time dispatch of the system;
- The Electricity Generation Corporation (Verve Energy) who own some 66% of the installed generation capacity and provide the real-time system balancing; and
- The Electricity Retail Corporation (Synergy) who provide electricity to consumers who do not have interval metering at their premises.

The rules governing how the market operates are covered within the Wholesale Electricity Market Amending Rules, established under the Electricity Industry (Wholesale Electricity Market) Regulations, 2004 which are, themselves, derived from the Electricity Industry Act. The IMO Board reports to the Minister for Energy, is advised by a Market Advisory Committee established under the market rules, with an appeals route to an Energy Review Board and with relevant approvals and market surveillance duties being undertaken by the Energy Regulatory Authority (ERA).

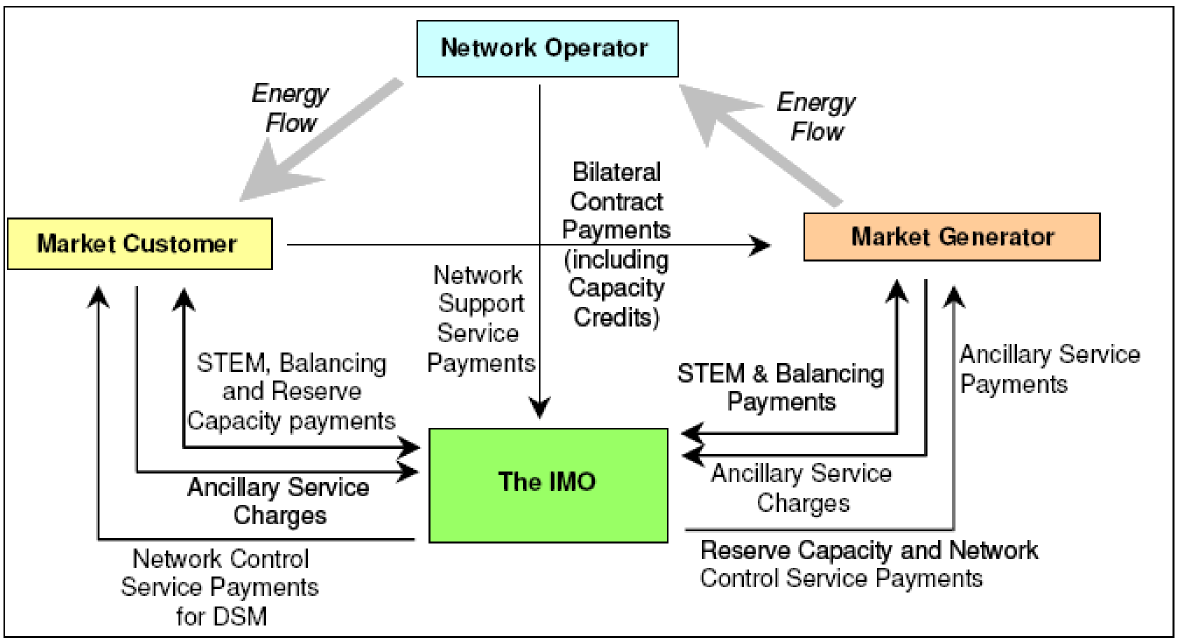
The market arrangements are made up of a number of subsidiary components;

- The Reserve Capacity Mechanism, based on Certified Capacity Credits being traded bi-laterally between market participants and auctions where the IMO may purchase additional credits. This mechanism also incorporates capacity contacted via Network Service Contracts, where generation may be procured to avoid network investments
- Long-Term Energy, based on bilateral trading between market participants;
- The Short-Term Energy Market (STEM), where variations in energy commitments are cleared by the IMO;

- Ancillary Services, where system support facilities are procured by the system operator, in accordance with the market rules; and
- Scheduling and Dispatch, where merit orders are established, based on submitted Resource Plans and prices for balancing the system in real time.

The following schematic provides an outline of the main cash-flows associated with these market elements.

Figure 17: Illustration of the Settlement Cash Flows (IMOWA – Wholesale Electricity Market Design Summary, 2006)



The market rules identify categories for all generation and demand facilities that may be operated under the market rules. These categories are as follows:

- Scheduled Generation; generation that may be offered to provide Capacity Credits, subject to being certified, may provide energy and be subject to schedule and dispatch and may not be intermittent;
- Non-Scheduled Generation; generation that may be offered to provide Capacity Credits, subject to some de-minimis level and may receive income for energy exports to the network, or offset demand and tends to be smaller, intermittent generation;
- Non-Dispatchable Load; normal demand that may be aggregated or not, depending on metering;

- Dispatchable Load; demand that may be subject to schedule and dispatch and would be eligible for Capacity Credits and energy balancing payments, for instructed load reduction;

- Curtailable Load; demand that may be reduced and is eligible for Capacity Credits; and

- Interruptible Load; demand that can be instructed to load shed, as an Ancillary Service and is eligible for Capacity Credits.

The Reserve Capacity Mechanism

The capacity market obliges Market Customers to procure capacity credits to match their expected demand and allows for Market Generators (or Market Customers, for suitable demand) to obtain certification for capacity credits that may then be offered to the market. The main emphasis of this arrangement is to seek to ensure that peak demand can be met. Further details on the capacity mechanism are discussed later in this section.

Long-Term Energy

Forward energy is procured via the bilateral contracts between Market Generators and Market Customers for capacity and will also include prices and volumes for energy. Energy is determined as being MWh over a given half-hour and the pricing for energy procured via the short-term and real-time processes incentivises participants to contract for their energy. These contracted volumes should be notified to the IMO. Such notifications can be made up to 7 days in advance of the Schedule Day (and can take the form of a standing volume).. All such submissions must be balanced, in that the volume to be provided onto the SWIS must match that to be delivered from it, as adjusted for system losses.

Short-Term Energy Market

On the Scheduling Day, the IMO will run the Short-Term Energy Market (STEM). The STEM allows participants to submit sell curves and buy curves, which are incremental offer volumes and prices and incremental bid volumes and prices, respectively. From generation, these two curves represent offers to provide additional generation and bids to reduce generation, whilst from Market Customers, the curves reflect offers to reduce demand and bids to increase demand. Market Generators must make any spare capacity available to the STEM, excluding any capacity which is required for Ancillary Services, the curves must have increasing price with increasing volume, bid prices must be greater than offer prices, offers must be less than the STEM Maximum price and all prices must exceed the Minimum STEM price. Market Generators that have liquid fuel (oil or distillate) fired plant may also offer alternative prices for using this fuel. These prices cannot exceed the Alternative Maximum STEM price and can match bid prices.

Once all submissions have been made (between 09:00 and 09:50 each day), the IMO will clear the STEM (between 10:00 and 10:30 each day). This process involves the ordering of bids and offers in price order and accepting such bids and offers until the two curves intersect. At this point the STEM price is established, it is subsequently paid to all accepted offers and by all accepted bids. The accepted bids and offers will all be deviations from the contracted position.

Participants who have had bids accepted will be debtors in the STEM, since settlement takes place in arrears and security will need to be provided to cover this debt. Margin calls may be made by the IMO, as this debt increases.

Ancillary Services

In common with most other electricity markets maintaining the system within operational standards requires the system operator to call-off Ancillary Services. These are defined in the market rules and are procured by the system operator via mechanisms approved by the Energy Regulation Authority. The following services are currently defined:

- Load Following; which may be provided using Automatic Generator Control (AGC), or may be manually provided;
- Spinning Reserve;
- Load Rejection Reserve; provided by Interruptible Load;
- Dispatch Support; which is associated with voltage support and other system stability related requirements; and
- System Restart.

All of the above will be covered by contracts with the system operator, will be called–off by the system operator within dispatch timescales and the associated costs are collected by the IMO on a monthly basis from participants. Spinning Reserve is paid for by generation, depending on the risk to the system from each facility, other services are paid for pro-rata by net demand.

Short Term Balancing and Settlement

To facilitate the real-time dispatch of the SWIS, all relevant participants, excluding the Energy Generation Corporation, must submit Resource Plans to the IMO, between the times of 11:00 and 12:50 on the Schedule Day, the Resource Plans provide the following:

- Committed MWh loads for their portfolio;

- MWh loads for each trading interval and intended instantaneous output at the end of each trading interval for each individual scheduled generation facility and for any individual dispatchable loads;
- Fuel to be used at each generation facility;
- Any shortages against commitment;
- Synchronization and de-synchronization times for each facility; and
- Prices for deviations in output (or load) and for de-synchronization. These may be standing data items.

The IMO will use these Resource Plans to generate merit orders for dispatch, taking due account of any alternative fuelling options and will provide these to the system operator by 1:30pm. The system operator may modify these merit orders to take account of any balancing support and ancillary service requirements from the Energy Generating Corporation and, in the normal course of events, will dispatch the Energy Generating Corporation accordingly. Except in emergency circumstances, no dispatch instructions would be given to other participants, aside from any balancing support that had been sub-contracted by the Energy Generating Corporation, via Balancing Support Contracts. Post-event, the system operator provides dispatch schedules to the IMO and these form the basis for the settlement of the trading day activity.

The settlement for on-the-day energy is based on three defined types of variation away from the position established via the STEM:

- If the outturn demand varies from that forecast in the STEM by 5% or more, then a revised clearing price is established, based on all additional increments of generation that would have been required to meet the additional demand (with the assumption that any curtailment of load, including any dispatchable demand, was to have been met by generation) and any generation shortfall. This new price is referred to as the Marginal Cost Administrative Price (MCAP). If no such adjustment is required, an MCAP is still established, but it is set as the STEM price for that particular trading interval. This price is then paid to all Scheduled Generation (and scheduled Dispatchable Load);
- For any generation that is dispatched away from its scheduled position, the price paid is the bid price for such deviations, as submitted in the Resource Plans;
- For any mismatches against schedule and instruction, two prices are established; the Downward Dispatch Administrative Price (DDAP), set to MCAP, factored by 1.3 over the peak period and

factored by 1.1 for the off-peak period and the Upward Dispatch Administrative Price (UDAP), set to MCAP factored by 0.5 for the peak period and set to zero for the off-peak period. Relevant participants will receive, or be liable for mismatches at either of these prices, or at bid prices, whichever is the least beneficial.

4.4.3 Specific Mechanisms aimed at Supporting Reliability and Security

Overview

The specific aspects for the arrangements in the SWIS which are aimed at supporting reliability and security are as follows:

- A form of Capacity Ticket mechanism;
- Provision of Operating Reserves;
- Short-term pricing for demand side measures; and
- Provision of Operating Reserves by Interruptible Customers.

The following focuses on the capacity mechanism and operating reserves with a summary of demand side measures only as the other measures are common to many other markets and can be considered as complimentary.

4.4.3.1 Capacity Mechanism

In order for a Market Generator to be able to offer capacity credits to the market, it must first obtain certification for that capacity. This is done by the Market Generator making an appropriate submission to the IMO, based on there being adequate access arrangements with one of the Network Operators and historic performance demonstrating that the capacity is genuinely available. For new or modified plant that has no performance history, provisional certification can be provided, along with the Market Generator providing financial guarantees. The offered capacity is provided in the form of an Availability Curve that identifies the duration over which a given amount of capacity can be sustained within the Capacity Year. This is also subject to the underlying requirements of forced outages being no more than 15% of the time and the combination of unforced and forced outages being no more than 30% of the Capacity Year. The Availability Curve will identify capacity down to the nearest 0.001MW, with availabilities exceeding; 24 hrs/yr, 48 hrs/yr, 72 hrs/yr and 96 hrs/yr. In order to provide suitable forward planning and to facilitate the market arrangements, the IMO undertakes assessments as to the amount of capacity needed, in the form of:

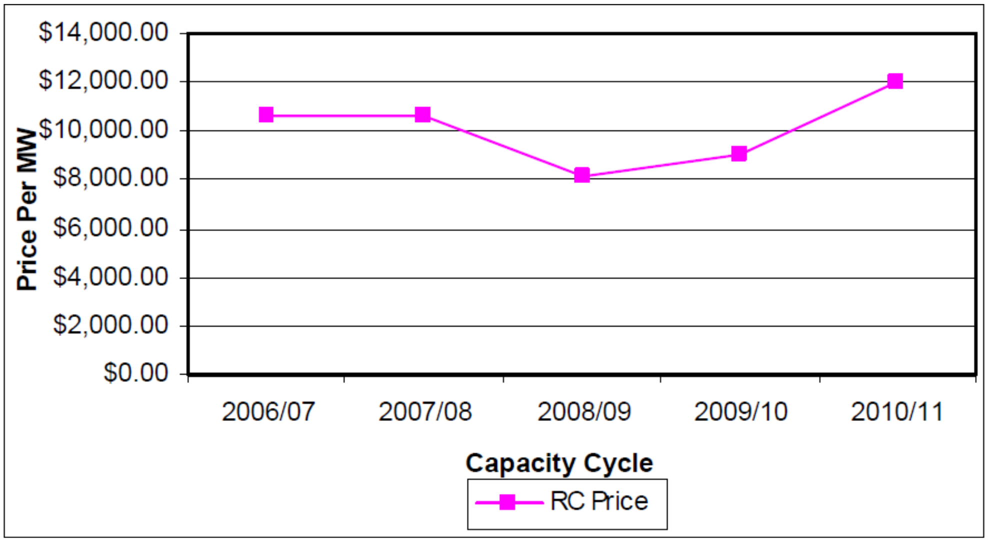
- Long-Term Projected Assessment of System Adequacy (PASA), from which an annual Statement Of Opportunities (SOO) is published;
- A Medium-Term PASA; and
- A short-Term PASA.

In so far as Market Customers are concerned, the IMO undertakes an annual forecast of the peak demand for the Hot Season with a 10% probability of it being exceeded. Market Customers then submit their forecast requirements and these are normalized against the IMO's forecasts and this process then feeds into the Statement of Opportunities (SOO) and confirms the requirement for each Market Customer.

In the first instance, Market Customers will procure capacity credits from Market Generators via bi-lateral contracts and any contacted volumes are then notified to the IMO. Periodically, the IMO will assess the net position of each participant and if there continues to be a shortfall, the IMO will undertake an auction, whereby it will invite offers of additional capacity from Market Generators and will clear the required volume at the highest price accepted by purchasing such volume itself. The IMO will also purchase capacity from Market Generators via Network Service Contracts. These are contracts that arise from periodic assessments of transmission capability, whereby a generation planting option is secured as an alternative to transmission reinforcement and such planting is secured via a Network Service Contract.

These payments are intended to cover the fixed costs of an open cycle peaking gas fired turbine and will also partially cover the capital costs of base load units. When the market first went live this payment was set at $10,625 per MW of capacity per month. It reduced in the 12 months from 1 October 2008, but has since increased again as is shown in the chart below. It should be noted this capacity mechanism does allow for the imposition of a cap in the STEM market which is based on the marginal costs of an open cycle gas turbine using natural gas. In the period from 1 November 2007 to 1st October 2008 this cap was set at $206 per MWh

Figure 18 Reserve Capacity Price per MW per Month (IMO Reserve Capacity Mechanism Review Report May 2009)



The settlement of the Reserve Capacity Mechanism will be based on volumes being adjusted for transmission and distribution losses (calculated as the marginal losses, averaged for the year at each node and weighted by demand at the node), with some account being taken of the STEM position and with further adjustments for any forced outages and subject to Certified Capacity Credits being validated by testing, which may be undertaken at the IMO's discretion.

The other key aspect of the Reserve Capacity Mechanism is that of credit cover, defined as Prudential Requirements in the market rules. Notwithstanding whatever credit cover arrangements may exist within bi-lateral contracts (which are a matter for the contract parties), Market Customers are debtors with respect to purchases made by the IMO and payment for those purchases is settled on a monthly basis, following meter data collection, some 70 days after the event and security for that debt must be provide by the Market Customers, accordingly.

4.4.3.2 Operating Reserve (including Interruptible Contracts)

Operating Reserves are defined within the market rules for the SWIS as specified components of the Ancillary Services to be procured by the system operator and called-off within scheduling and dispatch to maintain system operating standards. These standards are set down in Technical Rules, which are established and maintained by each network operator.

The types of operating reserve that are utilized are as follows:

- Load Following Services; to be provided by Scheduled Generation and is the frequency keeping service;

- Spinning Reserve; may be provided by Scheduled Generation, Dispatchable Load and Interruptible Load and requires the holding of capacity for response to retard frequency drops and for Scheduled Generation and Dispatchable Load to support the avoidance of involuntary load curtailment. This service is sub-divided into three categories, based on response times and sustainability (delivery within 6 seconds and sustainable for a minimum of 60 seconds, delivery within 60 seconds and sustainable for a minimum of 6 minutes and finally, delivery within 6 minutes and sustainable for a minimum of 15 minutes); and

- Load Rejection Reserves; may be provided by Scheduled Generation and Dispatchable Load and requires capacity such that rapid load reductions can be compensated for, either by rapid reductions in generating output, or by the dispatch of replacement demand. This service is sub-divided into two categories, delivery within 6 seconds and sustainable for a minimum of 6 minutes and delivery within 60 seconds and sustainable for a minimum of 60 minutes.

Each year the system operator will review the requirements for all Ancillary Services, based on an assessment of expected system configuration and demand/generation disposition. On the basis of this review and subject to the approval of the IMO, the system operator will produce an annual Ancillary Services Plan, identifying the services to be provided by the facilities of the Electricity Generating Corporation and by the facilities of participants contracted to provide Ancillary Services. Where new or additional services are required these will also be identified and the system operator will invite tenders to provide identified services via Ancillary Service contracts. The system operator will review all submitted tenders and will seek to contract for the most cost effective service provision, noting that for load following and for spinning reserve, the Electricity Generating Corporation is established as the default provider. Any such contracts must first be approved by the ERA, who may go to consultation before any such approval.

Once a contract is in place, these can then be called-off as required, subject to the relevant facility being available in the balancing mechanism.

Payment for these identified Ancillary Services are administered within the market rules and are made monthly in arrears, based on the availability of the service, along with any balancing energy payments being made as they arise. For Load Following, an additional capacity payment is also made. Load Following costs are allocated pro-rata to demand, net of any unscheduled generation, Load Rejection is allocated to demand, pro-rata and Spinning Reserve is allocated to generation, pro-rata on its contribution to the need for spinning reserve, based on the size range of each generating facility.

4.4.3.3 Demand Side Measures

Demand Side Measures are incorporated into all aspects of the market rules.

In so far as short-term pricing is concerned, the on-the-day balancing arrangements allow for demand that is dispatchable to respond under instruction, based on submitted prices, for given trading intervals (subject to any limitations regarding dynamic characteristics, which must also be submitted). Curtailable load may also contribute to balancing, albeit in a more limited fashion. Balancing arrangements are normally contracted for via the Energy Generating Corporation, which carries the principal responsibility for providing balancing action to the system operator. Demand that is either dispatchable or curtailable may participate in the STEM and contribute to a more optimal energy clearing price and volume, which they also benefit from. The STEM is also based around submitted prices for deviations away from contracted volumes, for each trading interval.

Dispatchable Load may also enter into Ancillary Services agreements with the system operator, to provide spinning reserve and/or load rejection reserve. Furthermore, interruptible load may also enter into Ancillary Services agreements for spinning reserve. These contracts allow for a volume of load management to be called-off against a bid price, within a merit-order scheduling and dispatch regime, as well as providing for additional income from the availability of the service.

A further facility within the market rules allows Market Customers to take account of potential load management in the context of the Reserve Capacity Market. Market Customers that anticipate possible load management capability within their portfolio may establish a Demand Side Management Programme (DSP). The DSP allows a Market Customer to commit to an overall volume of load management, which then attracts capacity credits and then subsequently uses up that commitment as load management volume is actually procured by the Market Customer. The DSP does, however, constitute a firm commitment to provide capacity and the Market Customer would be liable for any unsold DSP volume, as an unfulfilled capacity credit.

4.4.4 Experiences to Date

The capacity reserve mechanism is the major technique used to provide security and reliability and has a relatively short history having only been in operation since 2005. However, it has been successful in procuring excess level of capacity for each of the last four capacity years. Table 4 demonstrates the capacity cushion levels since it has been in operation.

Table 4 Capacity Cushion Levels - Reserve Capacity Mechanism Review Report May 2009

Run in	Capacity Year	Required Capacity (MW)	Procured Capacity	Capacity Cushion
2005	2005/06[44] 2006/07 2007/08	3531 3744 4000	3531 3744 4000	0 0 115
2006	2008/09	4322	4600	278
2007	2009/10	4609	5136	527
2008	2010/11	5146	5258	113

The call for expressions of interest in 2009 for the 2011/12 Reserve Capacity Year saw 1,278 MW of new capacity potential proposed. This new capacity combined with approximately 5,043 MW of Capacity Credits from existing and committed plants should easily pass the Required Capacity level of 5,314 MW.

The Capacity Mechanism has seen strong investment in new facilities across most fuel types, but particularly in gas only capacity, which makes up 44% of the new capacity. Dual firing plant, whilst seeing a growth in capacity credits has seen its relative share of the market shrink. As dual fuel and liquid only plants have played a part in maintaining system reliability and security there is some concern on this drop in the relative level of capacity. The IMO Board of Directors has therefore requested that the IMO investigate ways to incentivise investment in dual fuel capability and this review of fuel requirements is currently being progressed. An overview of the importance of different fuels in delivering this increased capacity is shown in the table below.

Table 5 Summary Measures of Fuel Composition (IMO Reserve Capacity Mechanism Review Report)

	Coal	Dual Coal/ Gas	Dual Gas/ Liquid	Gas Only	Liquid Only	DSM	Renewable
Initial Number of Capacity Credits (MW)	1044	509	736	996	65	111	69
Number of Capacity Credits in 2010/11 (MW)	1518	564	1012	1801	72	154	137
Net change in Capacity Credits (MW)	474	55	276	805	7	43	68
Initial % of Capacity	29.6	14.4	20.9	28.2	1.8	3.1	2.0
% of Capacity in 2010/11	28.9	10.7	19.2	34.3	1.4	2.9	2.6

[44] During the market transitional years of 2005/06 and 2006/07 the required capacity was set at the level procured

Overall the capacity levels in Western Australia seem strong and the executive summary of the Reserve Capacity Mechanism Progress Report noted that there was currently sufficient capacity projected to enter SWIS to comfortably meet projected demand until the 2014/15 period.

4.5 Great Britain (BETTA)

4.5.1 Market Context

The Great Britain (GB) Electricity Supply Industry was privatised in 1990 and has successfully operated in a liberalised environment since, albeit with some significant changes having occurred both to the industry structure and to the market itself. Following an initial proliferation of competitors much consolidation has taken place in the industry over the last 10 years and the wholesale market is now largely made up of 6 vertically integrated players i.e. companies with generation, trading and retail supply assets. Nonetheless there is full competition in generation (introduced at the opening of the market in 1990), supply (also introduced in 1990 but fully opened down to domestic level in 1998) and forwards and futures markets have developed where a range of standard and structured products are bought and sold by suppliers, generators and trading parties.

A bilateral market was introduced in 2001 which means that only imbalances are settled centrally whereas the predecessor of the bilateral market (the Pool, introduced in 1990) settled all energy through the central clearing mechanisms (though contracts in the form of Contracts for Differences were common outside the Pool arrangements).

Until April 2005 the electricity wholesale market in Scotland operated under different arrangements from those in England and Wales. The British Electricity Trading and Transmission Arrangements (BETTA) introduced a single wholesale electricity market for Great Britain with a single transmission system operator (National Grid) who is required to independent of generation and supply assets. There are three transmission network owners who are responsible for maintaining and developing the transmission systems in three geographic regions, the north of Scotland, South of Scotland and England & Wales.

In addition to the introduction of new transmission arrangements, BETTA also extended the England and Wales trading arrangements (NETA – the New Electricity Trading Arrangements) to Scotland. The legislation which underpinned BETTA was delivered in the Energy Act 2004.

Turning to the market structure, there are seven Distribution Businesses (see Table 6), three transmission asset owning businesses (National Grid in England and Wales, Scottish Power and Scottish & Southern Energy[45]) and, as mentioned above, a single system operator (National Grid) responsible for system

[45] Technically the Licensees are the Transmission Owners rather than the parent companies but the distinction is not drawn for the purposes of this paper.

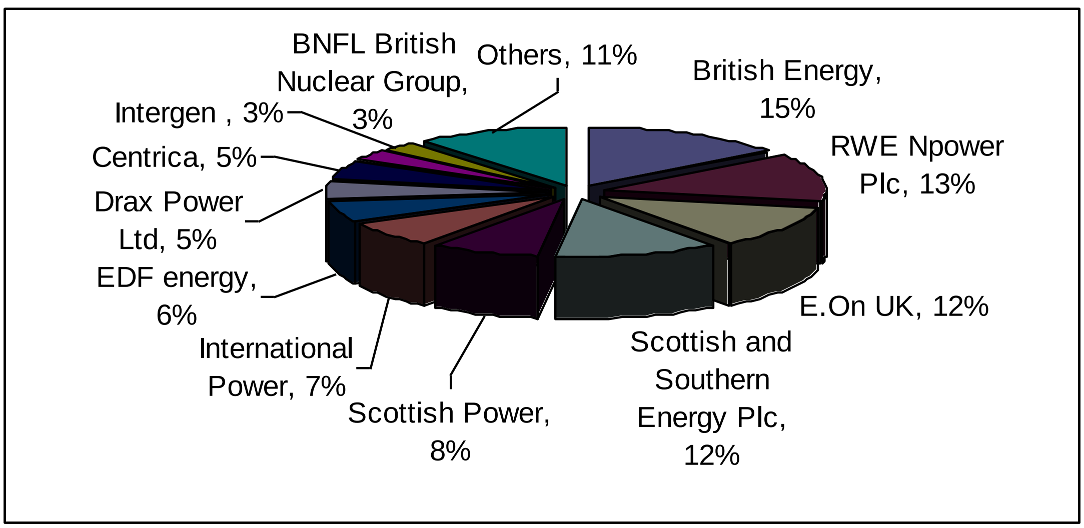
operation activities across Great Britain. The network and system operation activities are regulated businesses that derive the majority of their income from the price controls set by the industry regulator Ofgem.

Table 6: Distribution Network Operator (DNO) Companies in the GB Market

DNO	Area
EDF energy	Eastern England, London & South East England
CE Electric (NEDL YEDL)	Yorkshire
Central Networks	East & West Midlands
Scottish Power (SP)	South Scotland, North Wales, Merseyside and Cheshire
Scottish and Southern Electricity (SSE)	North Scotland Southern England
Electricity North West	North West
Western Power Distribution	South Wales & South West England

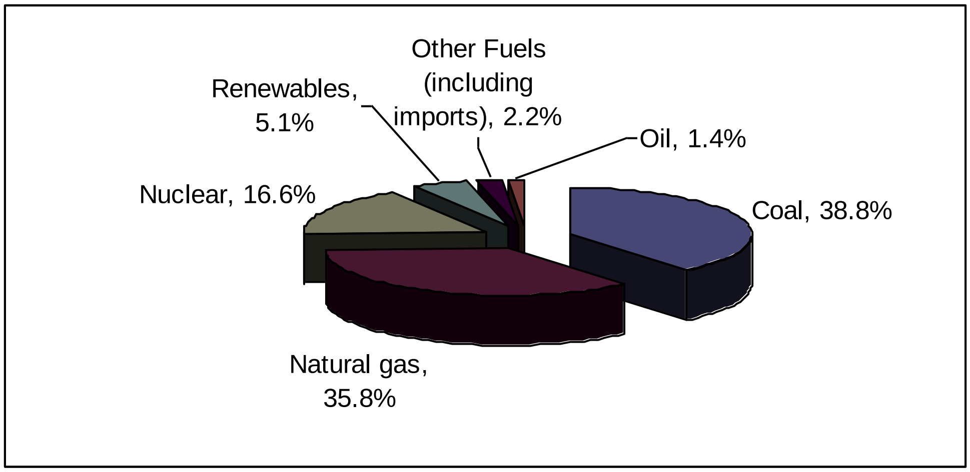
The breakdown of major generation ownership is heavily concentrated with the largest eight companies holding circa.80% of the total GB generation capacity and four of those accounting for over 50% of GB capacity. The breakdown of major generation ownership is illustrated more clearly in Figure 16 below.

Figure 19: Owners of Large Power Plants



British Energy[46] currently operates the majority of the nuclear plant in GB (with BNFL accounting for the remaining nuclear plant) with E.On, RWE and the others operating largely gas or coal fired thermal plant. A relatively small proportion of the total generation mix is currently renewable generation although many GWh's of additional capacity is planned. The island also benefits from two interconnectors (one to France and the other to Northern Ireland) with others planned to the Netherlands, the Republic of Ireland and Belgium. The figure below shows the electricity generation mix for 2007.

Figure 20: GB generation mix by fuel type (2007) ***(Source: BERR – Dukes 5.4)***



The following table presents a summary of the main characteristics of the GB market.

Table 7: Installed capacity and total electricity production (end of 2007 data from BERR)

Generation capacity (as of end of May 2008)	75.97 GW
Total Energy Demand	350 TWh
Peak demand	61.3 GW
Inter-connectivity	2 GW with France, 450 MW[47] Island of Ireland
Imports	8,613 GWh
Exports	-3,398 GWh

46 British Energy was bought by the French company EDF earlier this year but is shown separately as it continues to operate as a separate organisation for the time being.

47 Constrained on the GB side to limit imports to GB to 80MW.

4.5.2 Overall Market Design

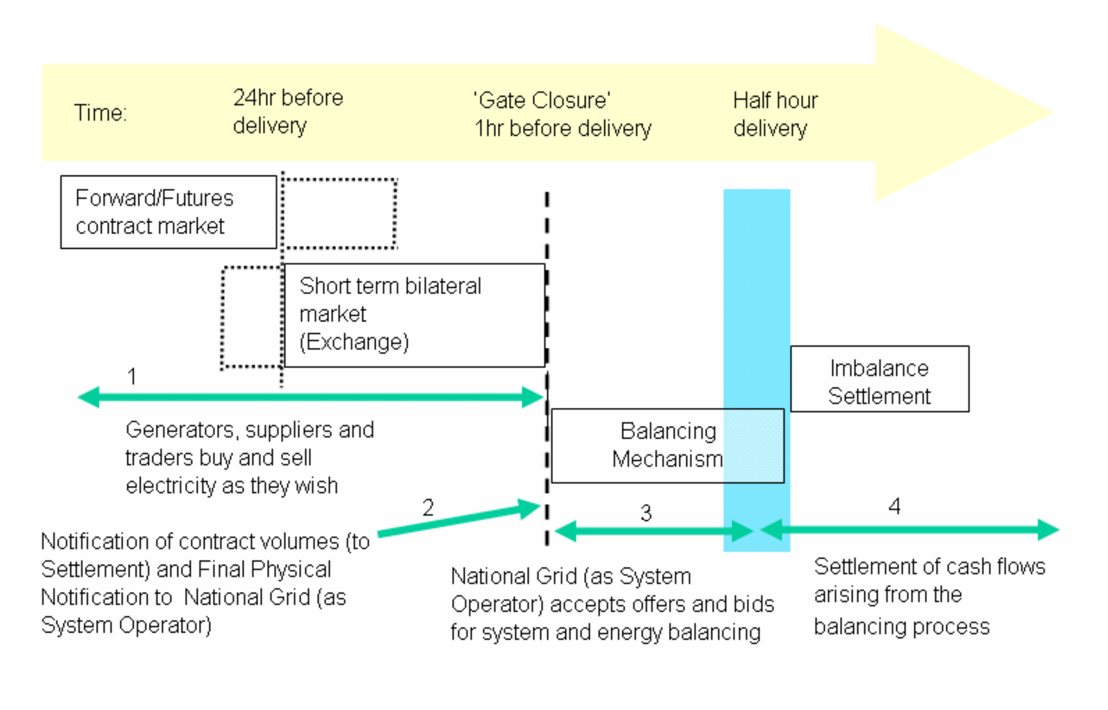
The wholesale electricity market arrangements do not dictate how electricity is bought and sold or the form of contracts through which it may be sold. However, the wholesale arrangements do impose a cut off for energy trading at 1 hour ahead of real time known as Gate Closure. After Gate Closure for a given period (half-hour) trading can no longer take place bilaterally in respect of that period and parties (both generation and supply as BETTA is a two-sided market) must have notified the GB System Operator (GBSO) either directly or indirectly of their intended output and/or offtake of energy from the transmission system to enable the GBSO to assess and then ensure energy balance and to manage the security of the transmission system.

Gate Closure is required for two reasons: Firstly it is highly unlikely that the aggregate total that generators intend to produce (as notified to the GBSO at Gate Closure) will meet the aggregate level of demand that suppliers intend to take – thus there will need to be "energy balancing" undertaken by the GBSO. The period between Gate Closure and the half-hour to which it relates provides time for the GBSO to plan and secure the required balancing services through the calling of contracts or the acceptance of bids and offers in the Balancing Mechanism (see below) from parties to deviate from the quantities notified to the GBSO at Gate Closure. Secondly even if the aggregate intended generation and supply did balance, there are technical reasons (such as transmission constraints) that require some generators to reduce or increase their output (or demand to increase or, more likely, reduce) to ensure that the transmission power flow capacities at a local and/or national level are not exceeded.

As indicated above the wholesale arrangements provide for a Balancing Mechanism to allow the GBSO to take energy and system balancing actions and ensure a real-time balance between generation and demand. The costs associated with energy balancing actions (i.e. the accepted bid and offer volumes and prices) are also used to derive the prices associated with imbalance cash out, i.e. the price paid to/by generators/suppliers who find themselves out of balance relative to their contract positions that were notified at Gate Closure.

An overview of the BETTA market design is shown in the diagram below:

Figure 21: Overview of BETTA Market Design



It is important to note that a generator can choose to seek to trade in the Balancing Mechanism either by selling additional power or for providing a "turn-down" service. In practice most generators post both bids (to turn down) and offers (to increase output) to the Balancing Mechanism as failure to do so might result in the GBSO instructing a reduction in the output from a power station without compensation for such activity.

It should also be noted that unlike many other markets, GB generators do not receive any capacity payments for simply being available. The only signal that encourages entry and exit to the market is the wholesale electricity price. There is some concern that this may be a crude mechanism that may risk over and under supply of capacity. However, the relatively short life of the current trading arrangements and the historic levels of capacity margin means this has not been fully tested yet.

Forwards and Futures Contract Markets

The bilateral contracts markets for firm delivery of electricity operates from a year or more ahead down to typically 24 hours ahead of real time, There are possibilities to trade in shorter timescales but the liquidity in these markets is thinner. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver/take delivery on a specified date and time for a given quantity of electricity at an agreed price. The markets are optional with participants having complete freedom to agree contracts of any form. Formal disclosure of price is not required although on brokered screens or exchanges the prices are disclosed but counterpart identities are not.

Role of ELEXON

ELEXON is the Balancing and Settlement Code Company (BSCCo) for Great Britain and is a not for profit company. It is an uncontrolled subsidiary of National Grid. The role of ELEXON is defined in the Balancing and Settlement Code (BSC) – the document which stipulates the market rules for GB - and breaks down into four main areas:

- Settlement of wholesale electricity balance and imbalance;
- Management of changes to the settlement systems and processes;
- Provision of assurance that BSC arrangements work correctly; and
- Supporting the BSC governance arrangements.

4.5.3 Specific Mechanisms aimed at Supporting Reliability and Security

4.5.3.1 Overview

The general approach of BETTA to new investment (and in fact to the whole arrangements) is to leave the market to deliver in response to price signals in the wholesale arrangements. However, it was expected that the demand side would play a more active role in the market place than is currently the case. In addition there are a number of National Grid initiatives that help with short term reliability and security. A key element of this is information. National Grid regularly publishes forecast data on the Balancing Mechanism Reporting Agent website. Such information includes forecast demand curves and forecast plant margins. The granularity of the data varies from week to week down to hour by hour as the timescales close in. In addition National Grid publishes its Seven Year Statement which sets out forecasts for the development of the networks, generation and load patterns and locations.

A register of all generation connected or that intends to connect in the future is also published allowing perspective generators to assess locations on the network where transmission capacity is most likely to be available. National Grid also publishes the Winter Outlook report to provide a view on the forecast status of the plant margin (among other matters) for the forthcoming winter period. All of this information is provided to enable participants to make their own decisions regarding investment and/or timing of availability and locations on where it is possible to connect. This all aligns with the "leave it to the market" ethos. National Grid's focus is on the short-term security with the actions it takes in the Balancing Mechanism and though some short-term bilateral contracting in the traded market.

A key objective of the market design is to provide incentives on participants (both generation and demand) to delivery reliability within the market. The existence of dual cashout prices in the Imbalance Settlement process is designed specifically to incentivise parties to (a) contract and (b) provide reliability. Any participant which proves unreliable is subject to the differential payment mechanism whereby, in simple terms, any excess energy is paid at a relatively low price while any shortfall in delivery is charged at a relatively high price. Changes have been introduced since the introduction of the arrangements to remove some of the volatility in imbalance prices which existed at the start of the market but the fundamental dual pricing system remains.

The following considers how the provision of demand services was intended when the market was designed and how reserves are procured.

4.5.3.2 Demand Side Participation

When the trading arrangements were changed in 2001 to the current bilateral contract mechanism, one of the key selling points was the introduction of a two-sided market where an appropriate level of supply and demand interaction would take place. It was envisaged that this interaction would take place in the forwards and futures markets and in the Balancing Mechanism, where participants could elect to offer services directly to the system operator.

In developing the arrangements it was recognised that much of the early focus on extending explicit demand response would be on those parties with half-hourly meters, as it was thought that suppliers would initially wish to focus on those customers where the pattern of consumption could be readily observed. It was noted that as experience developed that it would be possible to extend such arrangements to the smaller customers probably by introducing half-hour meters as metering costs fell.

Many trading parties entered the market on or around the implementation of the new arrangements and they saw the opportunity to offer risk management services to half-hourly metered customers, allowing them to play a more active role in managing their price risk. With the incentives that the arrangements created the key driver for generators and suppliers was to hedge their exposure to price fluctuations both through managing their imbalance price risk and their exposure to forward markets.

A number of Consolidators[48] entered the market with a view to realising the potential of the demand-side. However, the arrival of these parties happened to correspond to a period when prices fell to historic lows which meant that many traditionally price responsive customers were happy to take fixed price contracts from suppliers at relatively low prices and lock these in for as long as possible thus reducing their need to proactively manage their price risk and/or contemplate active demand management strategies.

48 Consolidation is a process where the partial or total outputs of a number of generators or the demand side are combined into one energy account. Because over and under-producing accounts are combined, the variations in output tend to cancel each other out, resulting in a relatively stable aggregate output.

In addition to active participation in the forwards and futures markets, provision was made for companies to actively participate in the Balancing Mechanism and compete with generator bids and offers. The Balancing Mechanism was designed to be principally a tool where the system operator would seek to balance the system in real time and would call upon bids and offers from suppliers and generators to actively manage their load in particular locations at particular times.

Despite this aspiration for a two sided market in the Balancing Mechanism, in the first year of operation of NETA only 0.15% of the offers accepted by NGC came from the demand-side. There is little evidence that this low level of activity has picked up more recently and a number of reasons can be put forward for this:

- The need for a co-operative supplier to bid into the Balancing Mechanism on behalf of the customers. Only licensed participants can bid into the Balancing Mechanism, so a customer would need to convince a supplier of the benefit of allowing it to bid into the mechanism and be prepared to deal with the administration this involved. This is on top of the difficulties of the customers being able to turn down demand quickly once its bids were accepted;

- The need to bid into the market as a single unit (BMU) located in a Grid Supply Point (GSP) Group rather than being allowed to aggregate load from dispersed sites across the country. National Grid needs location specific load in order to utilise the demand changes particularly to overcome constraints. This makes it difficult for a group of smaller sites in different GSP Groups to reach a level at which their bids may be utilised by National Grid;

- For domestic customers the settlement process relies on profiling rules which have limitations particularly the fact that they are designed for static half hourly boundaries. This could make it difficult for bids to be properly settled; and

- Meter splitting was included as part of the Balancing and Settlement Code rules, which would have enabled one supplier to be able to take control of the flexible load and participate in the Balancing Mechanism. Unfortunately, many suppliers put re-openers in their supply contracts with customers which meant their existing suppliers would wish to re-negotiate the entire contract if the load and profile of demand were changed in any way.

4.5.3.3 Reserves

National Grid procures so called Balancing Services (see below) in accordance with its Transmission Licence. This obliges National Grid to “operate the transmission system in an efficient, economic and co-ordinated manner” and also requires a number of statements and reports on the procurement and use of Balancing Services to be established.

Where there is, or is likely to be, sufficient competition in the provision of a Balancing Service, National Grid seeks to procure that service via an appropriate competitive process or market mechanism. The services which are procured via the regular tender market arrangements are:

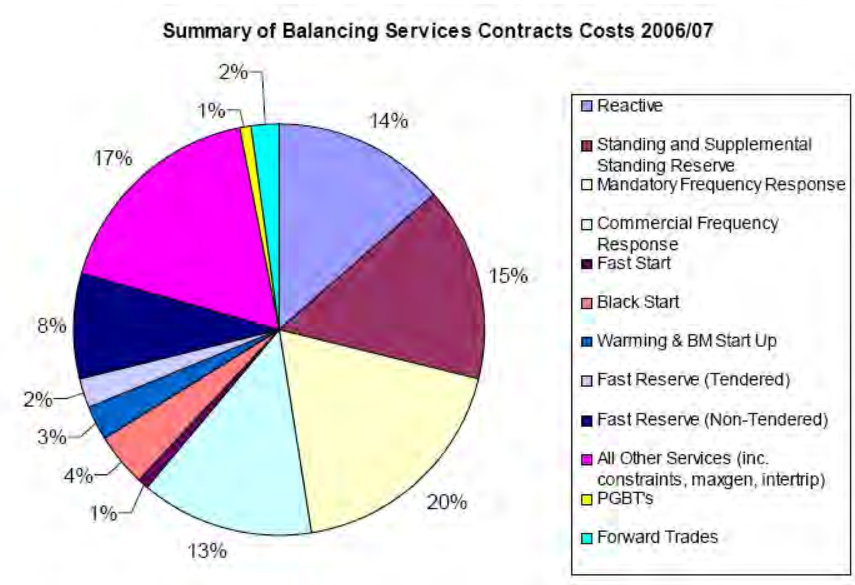
- Reactive Power;
- Fast Reserve;
- Short Term Operating Reserve; and
- Tendered Frequency Response.

Where National Grid considers that there is insufficient competition in the provision of a Balancing Service (e.g. where there is some form of local monopoly) they contract for such provision on a negotiated bilateral basis. Services that are procured by these Non-Tendered Bilateral contracts are:

- Mandatory Frequency Response;
- Commercial Frequency Response;
- Fast Start;
- Black Start;
- Fast reserve (Non-Tendered);
- Intertripping;
- SO-to-SO services; and
- Maximum Generation Services.

Figure 22 shows the split of the different services procured by National Grid. It is interesting to note that over 60% of the procurement costs are for Commercial Services that assist National Grid in meeting its licence obligation and which will be negotiated between the participants and National Grid either through a market competition or a bilateral negotiation.

Figure 22: Split of Balancing Services Costs 2006/2007 from Procurement Guidelines 2006/2007



The outturn costs of the Ancillary Services procured by National Grid for 2006/07 total c. £330m.

Table 8: Costs of Ancillary Services from Procurement Guidelines Report 2006 - 2007

Balancing Service	Info Provision	Value
Reactive Power Market	Utilisation Volume (MA) Utilisation Volume (DefaultPM) Total Spend (MA) Total Spend (Default PM)	5,530 Gvarh 18,659 Gvarh £13m £40m
Standing Reserve	Annual Average availability payments: Non-Working Days Working Days Total Spend Total Volume	 £5.55 £5.55 £48m 174567 MWh
Supplemental Standing Reserve	Annual Average availability payments: Non-Working Days Working Days Total Spend Total Volume	 £N/A/MW/h £6.02 10m 2503 MWh
Mandatory Frequency Response	Holding Volumes & Prices: Average Volume held MW Average price £/MW/h Total Holding Spend Total Response Energy Payment Spend	Primary / Sec / High 459 326 765 3.30 3.46 7.89 £73m (£3.00m)
Commercial Frequency Response	No. Of Contracts Total Spend	5 £52m
Fast Start	Total Spend	£4
Black Start	Total Spend	£16m
Warming / BM Start Up	Total Cost of Warming & Hot Standby /BM Start Up Number of instructions (warming)	£11m 651
Fast Reserve-Tendered	Total Spend on Availability & Utilisation	£8m
Fast Reserve Non-Tendered	Total Spend on Availability	£32m
SO to SO	Volume Imported Volume Exported Total Spend	258 GWh 72 GWh £23m
System to Generator operational inter-	Capability Payments Utilisation Payments	£0.0m £0.3m
Commercial Intertrip Service	Total Spend	£8m
Ancillary Constraint Contracts	Total Spend	£35m
Maximum Generation Service	Total Spend	£0.014m
All Other Services	Total Spend	£3m

There is no requirement for these to relate to costs of providing the services. For many of the services there is some discretion in the exact technical service that the provider offers and therefore the price cannot be simply set for a particular service as technical parameters will vary. Each provider of necessary and commercial balancing services will have a bilateral Commercial Services Agreement (CSA) with National Grid. This CSA contains provisions for any System Ancillary Services and Commercial Ancillary Services that may be agreed between parties from time to time.

In order to encourage the system operator to be innovative in looking at ways to reduce costs, each year Ofgem develops a system operator incentive scheme. The scheme establishes cost targets that National Grid is expected to achieve in performing its system operator roles and if actual costs are below the relevant target, National Grid is permitted to receive an incentive payment, and similarly if actual costs exceed the target, it faces an incentive penalty.

Following privatisation of the GB industry in 1990 there was some limited development of commercial Ancillary Services but essentially there was a "roll over" of the existing service arrangements into the new Pool market which other than adopting price based principles was little different in structure to the public centralised despatch approach. It was the implementation of the bilateral market in 2001 which provided the main trigger for the first major development of Ancillary Services. The radically different structure of the market and in particular the concepts of self despatch up to a short notice Gate Closure saw National Grid develop some new services such as Warming and Hot Standby (this service ensured that flexible oil plant which were expensive and might otherwise be unavailable, were available to assist balancing in real time).

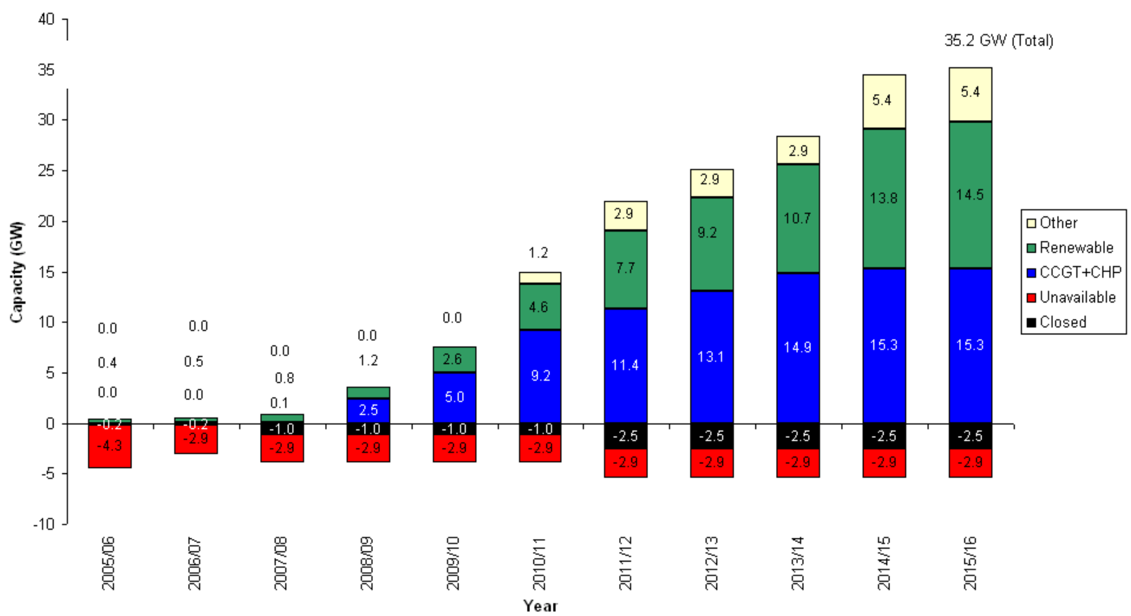
Since 2001, there has been substantial development in the Ancillary Services procured by National Grid, as Ofgem have pushed for more market and/or tender based approaches to procurement and also pushed for an ever increasing degree of information transparency. Although many Ancillary Services were becoming procured via market approaches, most were still procured on an annual basis. In 2003 due to prevailing market circumstances i.e. collapsing wholesale prices, many generators chose to mothball various units. Consequently National Grid found itself potentially short of generation for reserve holding and thus introduced a new Ancillary Services within year (Supplementary Standing Reserve) to ensure sufficient reserve was contracted. This is symptomatic of the development of the ancillary service markets in the last five years with more regular tender process for different Ancillary Services being introduced, to the point that many are now procured on a monthly basis.

Most recently, in response to feedback from the industry during a review of its approach to reserve, National Grid developed and introduced a new Reserve service, STOR (Short Term Operating Reserve). This replaces Standing Reserve, Supplementary Reserve and Warming & Hot Standby with a Reserve service which is more accessible for a wide range of potential providers. Fundamentally again the aim of this is to reduce SO costs via increased competition for provision.

4.5.4 Experiences to Date

As noted at the beginning of this section there has been considerable consolidation in the sector following the introduction of the new arrangements in 2001. Initially a number of new players entered the market but with the collapse of Enron and the withdrawal of many other active traders, liquidity in the markets reduced significantly and parties exited or sold their interests. The market has been successful in delivering a good degree of reliability with no significant events having occurred. Furthermore, a significant queue of generation capacity awaiting connection to the transmission system has built up, with National Grid's latest statistics showing a projected increase of 26.2 GW over the current position by 2015, including some 10 GW of gas plant, 3.3GW of coal and 2.1 GW of new interconnector capability. In addition some 14 GW of new nuclear power stations have been identified as seeking connections with the first ones due to connect in 2017/18. Many factors can be considered as influencing this. Firstly European Legislation will see a number of older thermal plant close in the coming few years as plant which has opted out of compliance with the Large Combustion Plant Directive (LCPD) will be required to close. The Government's own analysis indicates 20GW of plant will need to close over the coming 10 years – some due to the LCPD and others through age. This constitutes almost 30% of the peak demand for GB. Figure 23 below shows the historic and projected change in generation capacity up to 2015.

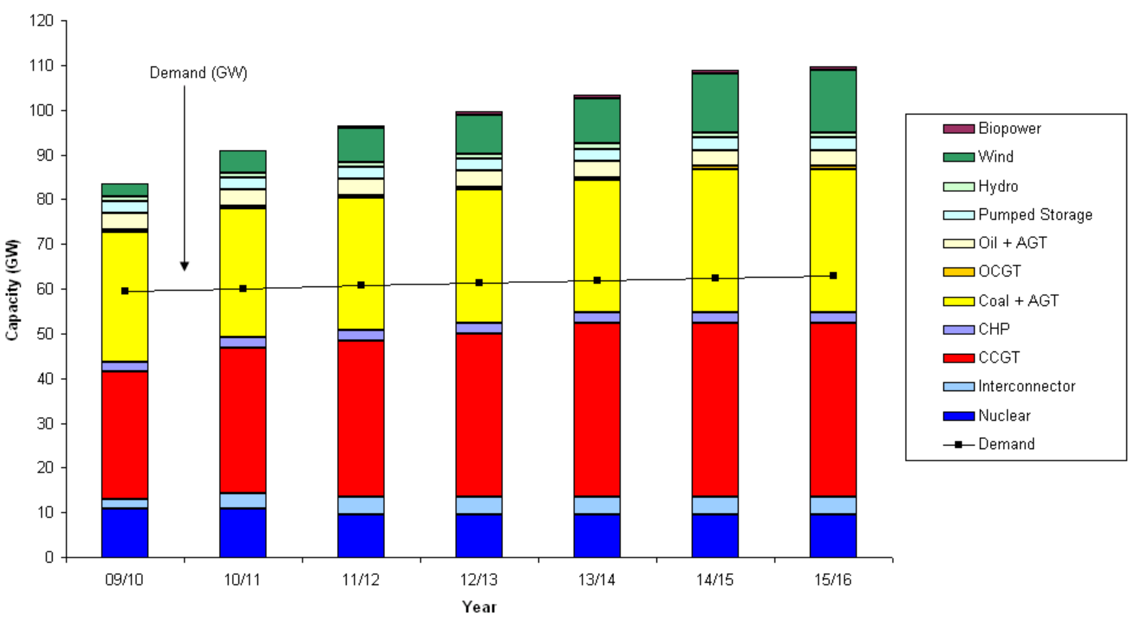
Figure 23: GB Changes in Generation Capacity 2005/6 to 2015/16: Source NGC Seven Year Statement May 2009



The fact that a large quantity of plant has decided to comply with the requirements of the Directive and are investing significant amounts in Selective Catalytic Reduction (SCR) equipment (many of which have already spent significant amounts on Flu Gas Desulphurisation equipment) suggests that forward market prices, impacted by the required plant closures, are sufficient to warrant the investment.

In addition, there are a significant number of renewable projects, particularly wind power projects, which are planned to be implemented in the coming 10 years (as can be seen from Figure 23 above and also from Figure 24 below) in order to meet the Government's carbon reduction targets (and which have been encouraged to enter via favourable pricing mechanisms). The intermittency of such plant means more flexible, generally thermal plant is required in order to maintain security. While such plant will generally not be built unless the market prices exist to sustain the investment there may be elements of portfolio players seeking to manage their risks which result in some of the new build projects currently in the queue.

Figure 24: GB Existing and Planned Transmission Contracted Generation: Source NGC Seven Year Statement May 2009



This need for flexible plant is further enhanced by the Government taking steps to make investment in new nuclear plant more attractive in order to stave off concerns on supply security – much of GB's gas supplies will, in the future, be sourced from countries outside of Europe and recent problems with the security of gas supplies from, for example, Russia raised concerns over the need for a more diverse set of energy supplies. This is not to say that the Government have sought to identify quotas for different fuel types, but rather they have sought to create a level playing field for each source of fuel to facilitate diversity via the market arrangements.

4.6 Single Electricity Market (SEM) for the Island of Ireland

4.6.1 Market Context

The Single Electricity Market (SEM) is the wholesale electricity market operating in the Republic of Ireland and Northern Ireland, which came into operation on November 1st 2007. As a gross mandatory pool operating with dual currencies and in multiple jurisdictions, the SEM represents the first market of its kind in the world. The market encompasses approximately 2.5 million electricity consumers, 1.8 million in the Republic of Ireland and 0.7 million in Northern Ireland.

The SEM is based on a traditional pool concept that incorporates a single system marginal price (SMP) and involves capacity payments. Under the SEM, generators bid on the basis of short-run marginal cost. Usually such markets permit generators to submit prices for production and allow competition to drive those prices down towards short-run marginal cost however in the SEM the two regulators (the Northern Ireland Authority for Utility Regulation and the Commission for Energy Regulation) concluded that the industry structure was such that insufficient competition currently existed to facilitate economic pricing in the market. Thus as part of a wider market power mitigation strategy, the SEM requires generators to bid short-run marginal costs and provides for such bids to be challenged by the regulators. Based on the submitted bids a single SMP is set for each half-hour trading period and suppliers pay SMP (plus capacity payment and a so-called imperfections charge – see later) while generators receive SMP (plus capacity payments and constraints payments).

The following table presents a summary of the key figures for the SEM.

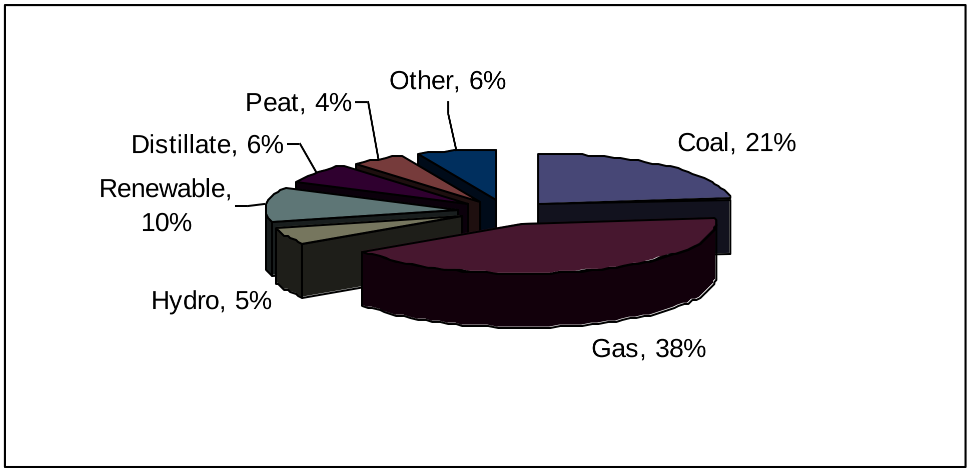
Table 9: Installed capacity and total electricity production

Generation capacity	9.7 GW
Total Energy Demand	36 TWh
Peak demand	6.7 GW
Inter-connectivity	450 MW[49] with Scotland
Imports	1,254.5 GWh
Exports	295.7 GWh

The SEM has a high dependency on electricity generation from fossil fuels with 88% of electricity generated by fossil fuels. The following figure presents the generation capacity mix of the market by fuel type.

[49] As noted earlier this interconnection is constrained on the GB side, limiting experts to GB from the SEM to 80 MW

Figure 25: SEM Generation Capacity Mix by Fuel Type



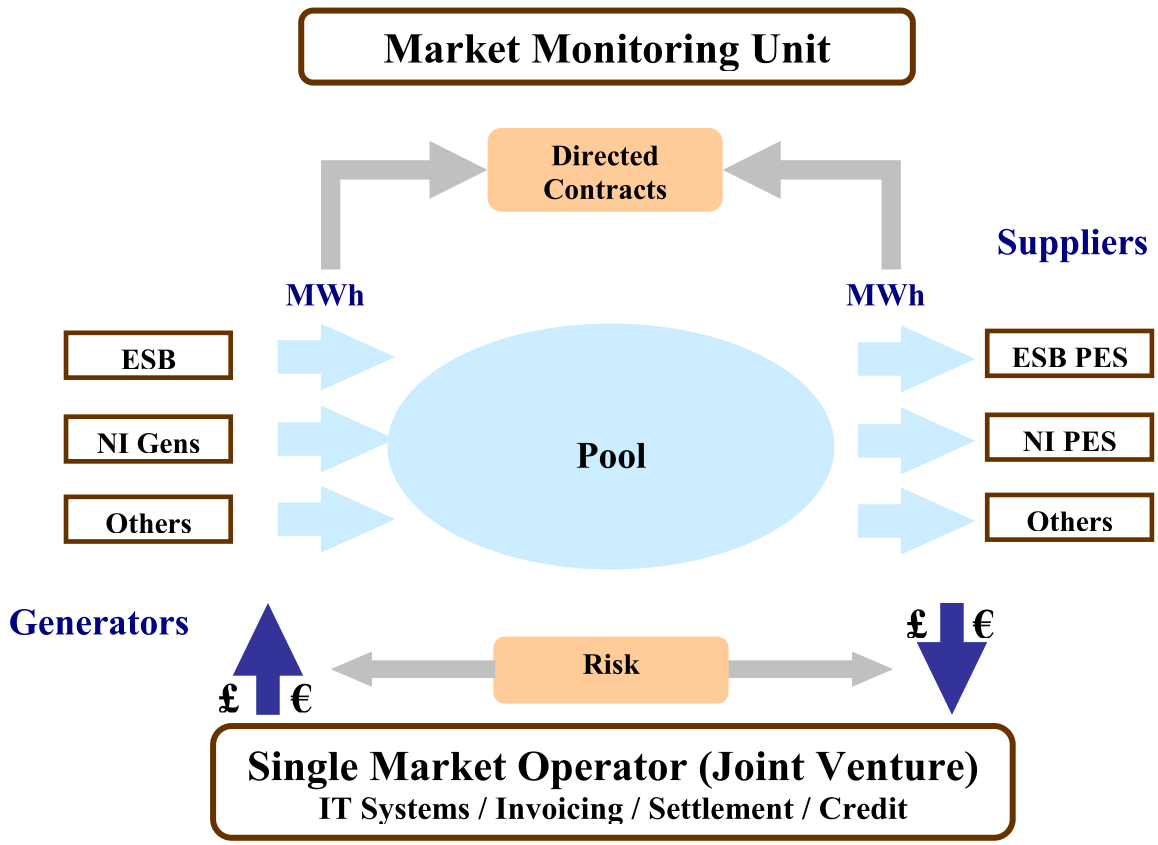
The market is dominated by ESB (Electricity Supply Board) PowerGen on one side and ESB PES (Public Electricity Supply) on the other. There are other large scale generation projects (such as those owned by Premier Power and Viridian) and a number of other smaller players in the generation (and supply) markets which provides a degree of competition however, as noted above, the two regulators concluded that it was necessary to mitigate against the dominant position of ESB until such time as a fully competitive structure emerged. The key element of the regulators' market power strategy involves mandatory offering of so called Directed Contracts by ESB at prices determined annually by the regulators on the basis of a regression formula. Supporting this strategy is the requirement for generators to bid short run marginal costs, with long run (fixed) costs being addressed through the capacity payment mechanism, and a division of the regulators (the Market Monitoring Unit) providing oversight of the operation of the market.

4.6.2 Overall Market Design

As mentioned earlier the SEM is a gross mandatory pool. Participation in the pool is mandatory for licensed generators and suppliers, save for generators which have a maximum export capacity of less than 10MW (the de-minimis threshold) for whom direct participation is voluntary. As a consequence, almost all electricity generated has to be sold into/purchased from the pool. Under the pool arrangements, the sale and purchase of electricity is conducted on a gross basis, with all generators/suppliers receiving/paying the same price for the electricity sold into/bought via the pool. Bilateral financial contracting (e.g. contracts for differences) can still occur, but the arrangements for doing so are separate from and not covered within the Trading and Settlement Code (TSC) which sets out the market rules.

A schematic overview of the SEM electricity market is presented in the figure below:

Figure 26: Overview of SEM Market Design ***(Source: Presentation of Tony Doherty, NIAUR, 'The single Electricity Market in Ireland')***



The processes, features and key players depicted in the above diagram are described in the following sections.

Day Ahead Complex Bidding

Participants are required to submit Offers into the pool in respect of each Generator Unit for a Trading Day and the data contained within these Offers applies equally for all Trading Periods (half-hour) within the relevant Trading Day. Offers must be submitted by Gate Closure, which is at 10:00 on the day before the relevant Trading Day (i.e. 10:00 D-1), but may be submitted up to 28 days before Gate Closure. Offers consist of Commercial Offer Data (prices, quantities etc.) and Technical Offer Data (dynamic parameters etc.).

Interconnector Units (pseudo generating units associated with trades across the interconnector to GB) are an exception to this rule. Interconnector Units are able to submit individual Offers to apply for each Trading Period in order to enable effective interaction with interconnected markets.

Standard Commercial Offer Data consists of:

- No Load Cost: a single No Load Cost which is the element of operating costs which is invariant with the actual level of Output;
- Start Up Costs: a minimum of one and a maximum of three Start Up Costs which reflect the costs associated with starting up the Generator Unit from cold, warm or hot states; and
- Price Quantity Pairs: a minimum of one and a maximum of 10 Price Quantity Pairs, each of which sets out a Quantity up to and equal to which the associated Price applies. Price Quantity Pairs must be strictly monotonically increasing with only one Price for each Quantity.

SMP Pricing

Under the pool arrangements all Generator Units receive and all Supplier Units pay the same energy component of price in a Trading Period for electricity; the System Marginal Price (SMP). The SMP is determined via the Market Scheduling and Pricing (MSP) Software (a complex linear scheduling programme) which is run by the Market Operator and which takes the offer data from generators and the actual market outcomes (in terms of the actual system demand and actual availabilities of the generating units) and is run in unconstrained mode to determine the half-hourly SMPs.

Capacity Payments Mechanism

While SMP pricing ensures that SMP reflects the value of energy, the Capacity Payments Mechanism attaches a value to the provision of capacity within the market. The Capacity Payments Mechanism is a fixed revenue mechanism with the amount of money allocated to the mechanism determined annually as the product of the annualised fixed costs of a best new entrant peaking plant and the capacity required to just meet the security standard. The allocation mechanism is intended to strike a balance between providing the highest capacity prices at periods of highest loss-of-load probability (or tightest margin) in order to value the provision of capacity appropriately, whilst at the same time providing a stable set of investment signals.

4.6.3 Specific Mechanisms aimed at Supporting Reliability and Security

4.6.3.1 Overview

One of the key reasons for the creation of the SEM was to enhance supply security by increasing the size of the market and so facilitate the possibilities for greater levels of investment. This investment is not only expected in generation but also in transmission. Currently a single interconnector exists between GB and Northern Ireland. A second interconnector between GB and the East cost of the Republic of Ireland is planned and further strengthening of the (now) integrated transmission network for the island is underway to reinforce the capacity of flows from Northern Ireland to the Republic of Ireland.

The SEM itself provides incentives and explicit mechanisms to seek to secure supplies, the most obvious of which is the capacity payment mechanism. In addition there are functioning (though not harmonised) ancillary service markets,) and demand side management schemes that contribute to system security. Each of these is considered below.

4.6.3.2 Capacity Payment Mechanism

During the design of the SEM the Regulatory Authorities initially considered the SEM to be an energy only, gross mandatory pool. In such a market Generators would need to be able to recover their long-run marginal costs (i.e. the combination of their short-run (variable) marginal costs and their fixed costs) through the single energy price. However the Regulatory Authorities were concerned that such an approach could lead to highly volatile market prices, especially at times of shortage as rarely used peaking plant sought to recover its long-run costs through very few operating hours.

Further consideration led to the conclusion that the SEM should include an explicit capacity mechanism as this would bring a number of desirable benefits to the SEM. This included:

- The prospect of more stable price;
- A reduction in the need for Regulatory intervention through the reduction in price volatility; and
- Facilitation of new entry generation through the reduction in investor risk premia resulting from the more stable and predictable cashflows introduced by a capacity mechanism.

The SEM capacity payment mechanism is a fixed revenue mechanism which establishes a fixed amount of money each year to be collected from suppliers and paid to generators under a set of prescribed rules. The amount of money to be allocated to the mechanism is based on the product of two numbers:

- A MW quantity – known as the Capacity Requirement - determined as the capacity required to just meet the security standard for the island; and
- A price determined as the annualised fixed costs of a best new entrant peaking plant.

The determination of the Capacity Requirement is based upon the adequacy assessment methodology employed by the system operators and creates a database of forecast generator availabilities accounting for both scheduled outages and forced outages, over which a forecast of demand for the relevant year is superimposed. Based on this data the system operators estimate the Loss of Load Expectation (LoLE – expressed as a number of hours per year) for the year in question and compare this with the applicable security standard for the island such that any surplus or deficit in generation capacity can be identified and the quantity of capacity required to exactly meet the demand within the security standard can be determined.

In establishing generator availabilities the Regulatory Authorities determined that historic average outage durations should be used so as not to allow atypical events to affect the forecast year on year, and that a target forced outage probability should be applied to all generator units to encourage improvements in unit availability. This target was set by reference to the actual values in Northern Ireland over the 5 years preceding market start-up and is 4.23% (actual rates in the Republic being 10% worse than this on average).

In determining the Capacity Requirement the contribution of wind power units is assessed differently to that from conventional units since their availability is determined more by the availability of fuel rather than mechanical capability. Wind power is therefore assigned a capacity credit, relative to the contribution available from conventional plant, by reference to work undertaken by EirGrid (the TSO in Ireland).

The price component is also determined annually and is based on the full project costs a developer would incur in constructing and operating a best new entrant peaking plant, taking into account an estimate of the inframarginal rent which such a plant would realise from operation in the energy market. Full project costs are considered to include matters such as site procurement, EPC contract, a long term service agreement and insurance costs. The methodology seeks to estimate the inframarginal rent such a plant would earn in the energy and ancillary services markets and deduct this amount from the annualised fixed costs so as to avoid “double payments”.

There is a complex mechanism for paying this fixed revenue amount out to generators which seeks to value capacity while still providing a stable revenue stream. Payments consist of three elements:

- A Fixed Amount, accounting for 30% of the total annual sum of money allocated to the mechanism and which is profiled over each month against forecast demand;
- A Variable Amount, accounting for 40% of the total and which is profiled over each month based on the forecast Loss of Load Probability; and
- An Ex-Post amount, accounting for the final 30% and which is profiled over each month based on an ex-post calculation of what the forecast Loss of Load Probability would have been had the actual demand and actual availability data for the month been known at the time.

The purpose of the three elements is to provide a degree of certainty in payment flows. The Fixed and Variable allocations across each month are know in advance of the month and therefore generators have signals regarding the need for capacity at certain times of the month, while seeking to reflect the actual value of capacity in any given period. The Variable element goes some way to achieving this thought the application of the ex-ante LOLP calculation but it is the Ex-Post element which provides the closest match to the actual value of capacity in each period. The system operators would have preferred the entire amount (or at least the vast majority) to be allocated to the Ex-Post element to minimise gaming opportunities and to provide the hardest incentive to ensure a plant is available (a plant unavailable for a single half-hour period could, in some circumstances, miss out on an entire months capacity revenue). However the Regulatory Authorities preferred to offer a degree of revenue stability so as to encourage new entrant generation to the market.

4.6.3.3 Ancillary Services

The SEM, in common with many other markets, employs Ancillary Services as a way of providing the system operators with tools to maintain the supply demand balance. Services are relatively standard as for other markets but are discussed here owing to changes currently being delivered to harmonise the arrangements across the SEM.

The arrangements are currently different in the 2 jurisdictions. In Northern Ireland Ancillary Services are wrapped within the so called System Support Services Agreements (SSSA) between the major generators in Northern Ireland and NIE Power Procurement Business (NIE PPB). The NIE PPB is the SEM facing part of the contractual partnership and is exposed to Pool payments and charges whereas the generators are isolated from the SEM by virtue of their contractual arrangements with NIE PPB. The SSSAs details all payments required to the generators including those for Ancillary Services such as reserves and reactive power. These contracts therefore effectively provide the vehicle for these generators to be incentivised to provide reliable supplies through a series of incentives and penalties that address energy production, availability and even outage scheduling.

In the Republic of Ireland the system operator contracts for reserves, black start and reactive power through long-term contracts in which the payment rates are reviewed annually.

Under new arrangements due to be introduced in October 2009, the System Operators have sought to harmonise the arrangements for the procurement of reserves (in various categories), black start and reactive power. Contracts will be struck with the generators at predetermined regulated payment rates (intended to be published annually) and payments will be made to the generators based on the response curves and levels of availability. In the event a generator fails to deliver the service when required, heavy penalties will be applied, generally based on multiples of the payment rate (for example failure to provide a reserve service is charged at 30 days reserve payment per incident). Again these are likely to be long term contracts but given that the rates are regulated (effectively the Regulatory Authorities assign an amount of money to be allocated to Ancillary Services for each year) it is not clear that the prospect of such contracts will entice the construction of new facilities, especially as the per unit charge will reduce as more generators enter the market and any revenue associated with the contracts will be netted off the amount allocated to the capacity mechanism – see above. However, as a short-term security/reliability measure, the design would suggest compliance by contracted generation given the severity of the penalties – such penalties could of course deter generators from seeking such contracts in the first place if they consider their reliability to be questionable and the rewards unlikely to be sufficient to maintain/improve a units performance and reliability.

Alongside the introduction of the new Ancillary Service regime a new system of penalties will be applied to generators in the event of a trip or a short notice redeclaration. The intention of this penalty is to provide an incentive to generators to notify the System Operators as soon as possible of a problem with a unit. Consequently the penalties increase the later the notification is provided to the System Operator. The penalty also reflects the fact that a large loss of MW output will have a greater impact on the system than a small number of lost MWs and hence the size of penalty is scaled to reflect the size of the loss. By incentivising improved early information flow to the System Operator it is expected to improve the security of the network in the short-term. Clearly such mechanisms provide no incentives for the maintenance of long-term system security, other than they may deter potential investors in generation or at a minimum will increase the financing burden for such new generators.

4.6.3.4 Demand Side Management Schemes

The final element worthy of consideration is the use of demand side management schemes. A number of these programmes exist at supplier level, mainly to improve a suppliers purchasing profile rather than for security reasons, but EirGrid also operate two programmes to facilitate security of supply. The first is the Winter Peak Demand Reduction scheme which aims to reduce peak demand between 17:00 and 19:00 hours on business days between 1 November and the 25 March and provides a reward to large customers for reducing consumption between these periods. Under the scheme customers' baseline consumption is calculated from consumption patterns from the previous winter. This baseline consumption is a MW figure that will apply throughout the two hour period. Customers then need to select a Committed Level to reduce their demand which can vary between 0 MW and the baseline. This Committed Level can vary from week to week but needs to be notified in advance. Payments for reducing demand are made up of three components:

- Reliability Payments - a reward for reducing consumption reliably down to the Committed Level during the 17:00 to 19:00 period. Any consistent gap between the Committed Level and their actual consumption level will represent an energy reduction for which they will not receive a reliability payment;

- Reliability Rebate (a deduction) - designed to penalise customers who do not deliver the energy reduction they have agreed as part of their Committed Level within a tolerance of 2% and rebate payments are limited to 5 times the daily reliability payments to encourage customers to reduce demand even if they had breached earlier in a month; and

- Profile Payment - an additional payment rewarding changes in energy consumption patterns over the peak period.

The second scheme is the Short Term Active Response (STAR) Programme and allows large electricity customers to be interrupted and provide Ancillary Services. The purpose of the programme is to provide very quick response to maintain system frequency in the event of a generator trip. This programme operates all year round not just for the winter peak. The customer is allowed to separate out interruptible from non-interruptible load, but the non-interruptible load will need to be measured separately as it will not be part of this programme. The programme runs from 07:00-24:00 daily and the customer receives no notice of an interruption. The duration of an interruption will depend on conditions on the electrical networks but would typically last for approximately 5 minutes and customers should expect around 10-20 interruptions per annum.

4.6.4 Experiences to Date

The SEM is still in very early days as yet having only been operational for 19 months and therefore it is difficult to judge how effective or otherwise the arrangements are. The capacity mechanism has attracted criticism from generators for setting, in their view, an unreasonably low target margin in the determination of the Capacity Requirement. The Republic of Ireland has historically had a quite tight margin and the equivalent all Island margin established through the Capacity Requirement (at around 5%) was considered much too small. However, many of the generators on the island have already recovered most of their fixed costs and therefore the capacity payment, which is paid to all generation irrespective of age, could be considered a bonus to such plant. The Regulatory Authorities did recognise early on that the annual review process in setting the amount of money to be allocated to the capacity mechanism could result in volatile pricing year on year, especially as the demand for new peaking plant rose and fell as it would impact directly on the estimation of the fixed costs of the best new entrant peaking plant. After a failed attempt to stimulate debate among the industry in 2008 on mechanisms to smooth out the potential volatility, the Regulatory Authorities issued an explicit consultation considering potential smoothing options earlier this year. The results of this consultation are still not published but it is unlikely that any decision could be accommodated within the price setting process for next year.

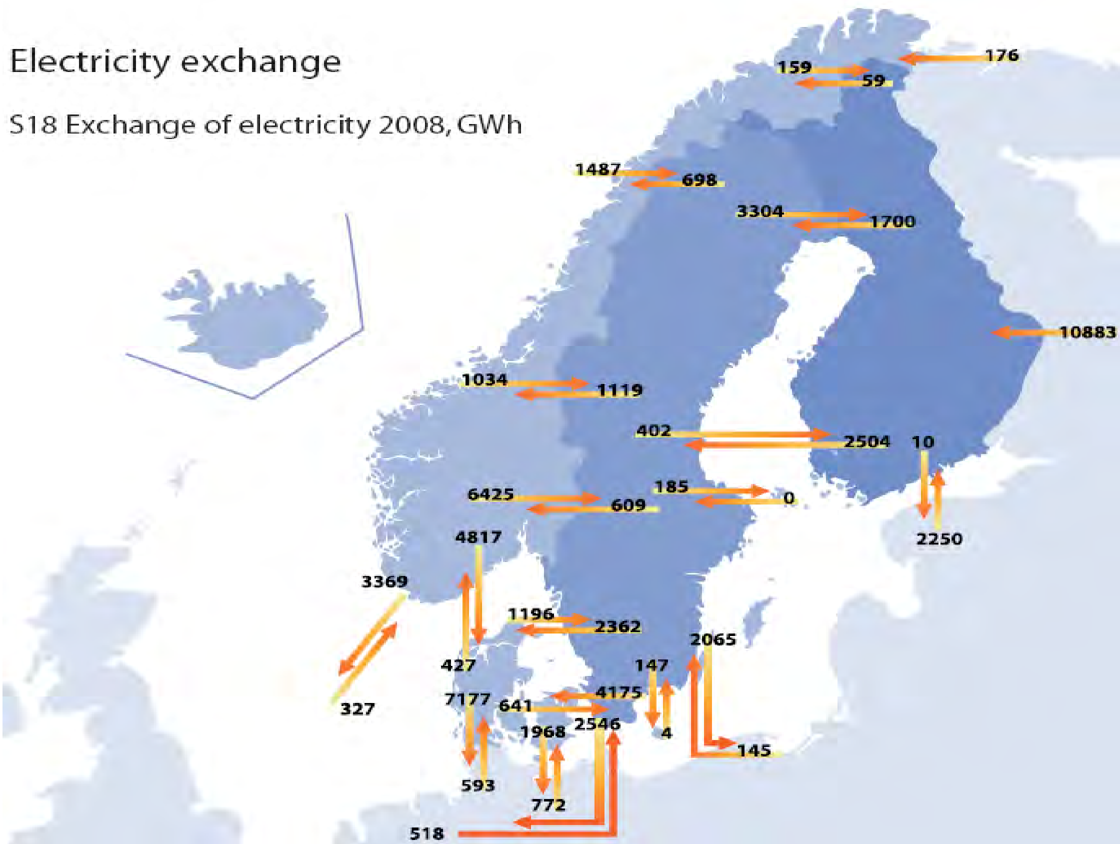
Despite these criticisms investment in new plant has occurred with the construction of a number of new CCGT plant as well as peaking OCGTs.

4.7 Nord Pool (Nordic Electricity Market)

4.7.1 Market Context

The community of Nordic countries, comprising Denmark, Finland, Norway and Sweden, represent an interesting example of the transition from independent national electricity markets to a regionally integrated wholesale electricity market. Market liberalization in terms of electricity trading and electricity production started in Norway in the early 1990s and proceeded in neighbouring countries by the end of the decade. After opening-up the national electricity markets for competition, a regional integration process started which led to the creation of a common Nordic wholesale electricity market with the Nordic power exchange Nord Pool being an integral component. An overview of the interconnected nature of these markets and the levels of flows that exist is shown in the diagram below.

Figure 27: Physical Electricity Exchanges in the Nordic Region. Source: Nordel Annual Report 2007.



The following section provides further details on the main participants in the electricity sector in the Nordic market.

Generation

The Nordic countries have a diverse generation structure with a good mix of generation types. Hydro power is the predominant source of power comprising over 50% of the region's installed capacity and actual generation. This capacity is mainly provided by the two largest markets of Norway and Sweden, although Finland also provides additional capacity. This hydropower is provided by a mixture of large rivers and reservoirs that are filled during rainy months and natural inflows.

The bulk of the remaining generation is derived equally from thermal stations (Denmark and Finland – mainly CHP) and nuclear power (Sweden and Finland). Whilst Denmark has a high quantity of wind generation the relative size of its generation capacity means the overall contribution of wind generation is still only 5% of the total. A summary of this generation capacity is provided in Table 10 below.

Table 10: Generation Structure in Nordic Countries by Energy Source on 31 Dec. 2008; Source: Nordel Annual Statistics, 2008.

			Nordic countries	Denmark	Finland	Norway	Sweden
Electricity generation	Total	TWh	397.5	34.6	74.1	142.7	146.1
	Nuclear power	%	21%	-	30%	-	42%
	Other thermal power		13%	70%	35%	0%	2%
	Hydro power		57%	0%	23%	99%	47%
	Wind power		3%	20%	0%	1%	1%
	Other renewable power		6%	10%	13%	0%	8%
Net imports		TWh	- 1.5	1.5	12.9	- 13.9	- 2.0
Installed Net Capacity	Total	MW	94,624	12,618	17,036	30,789	34,181
	Nuclear power	%	12%	-	16%	-	26%
	Other thermal power		25%	70%	54%	2%	15%
	Hydro power		52%	0%	18%	96%	47%
	Wind power		5%	25%	1%	1%	3%
	Other renewable power		6%	5%	11%	1%	9%

- = Data are non-existent; 0 = Less than 0.5 %; Nordic countries without Iceland;

This generation capacity is mainly provided by a number of dominant national players. At the top of them is Swedish Vattenfall AB with a market share of more than 15% of installed capacity in the Nordic region, followed by Norwegian Statkraft and Finish Fortum Oy, both accounting for more than 10% of installed capacity in the Nordic region.

Transmission and Distribution

The Nordic transmission grid (Nordel) connects the national high voltage transmission grids of Eastern Denmark, Finland, Norway and Sweden, operated by the four transmission system operators

Energinet.dk, Fingrid, Statnett and Svenska kraftnät, respectively. The interconnection of the national networks assists in providing both security of supply and an efficient exchange of electricity in the region. This efficient exchange is intrinsically tied to the Nord Pool market.

The Nordic transmission grid also interconnects the Nordic countries with adjacent countries, like Germany, the Netherlands, Estonia, Poland and Russia, which enables these countries to participate in the Nordic market. These interconnections vary from 350 MW up to 1300 MW. Notably, there is currently no transmission line between Eastern Denmark and Western Denmark, with the latter being connected to the Western European network UCTE.

Distribution

Electricity distribution in Nordic countries is characterized by a mix of public institutions (cities, municipalities) and a few large market players (Fortum, E.ON Sweden, Vattenfall, Statkraft, DONG) being shareholders of a number of DSOs/utilities. Denmark is an exception to this policy with ownership of the majority of utilities residing in the hands of cooperatives which are controlled by customers.

Table 11: Number of DSOs by Country, Source: Smart Metering and Wireless M2M, Berg Insight, 2007.

Country	Denmark	Finland	Norway	Sweden
Number of DSOs	100	89	130	152

Electricity Retail Market

Despite the existence of the integrated wholesale electricity market for more than 10 years, there is still no common retail market in the Nordic countries. This means that markets are separated, a fact which can be studied considering the following differences between countries:

Table 12: Retail Companies in Nordic Countries in 2007 (approximate values); Source: NordREG Nordic Market Report 2008.

Country	Denmark	Finland	Norway	Sweden
Number of Retailers	70	70	200	115

In many of these markets there are a handful of large suppliers that have a significant share of the market. As well as consolidation another sign of a well-functioning market is customer switching. Whilst allowed in all markets this varies from 2% of household customers in Denmark to 9% in Norway.

The Nordic Regulators are working towards a common Nordic retail market. There are a number of steps that may be needed to encourage competition with cross national suppliers. This includes standardisation of the balancing regimes and switching rules across countries and consistent market rules and regulatory frameworks.

4.7.2 Overall Market Design

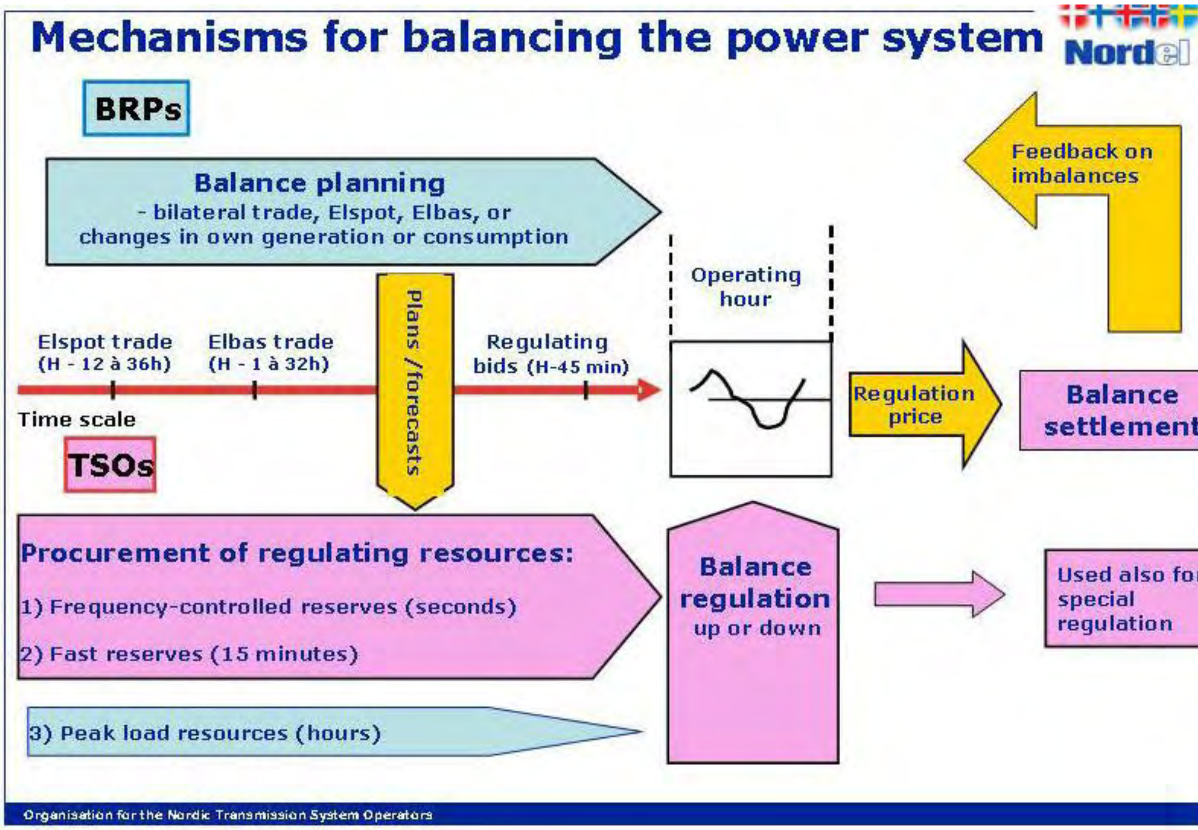
The Nord Pool market has been a core-component of the multinational Nordic electricity market, to which the Nordic countries connected one-by-one, and today facilitates much of the generation traded between countries. The Nord Pool market is open to generators, industrial consumers, retailers, grid owners and others.

The Nordic power market is based upon a Market Coupling / Splitting approach designed to handle temporary restrictions on transmission and interconnection lines and make best use of generation capacity. This is a form of an implicit action where the flow on an interconnector is found based on market data from the market place in the connected market. The handling of capacity is contained in the prices for electricity in the markets.

This approach taken divides each Nordic country into at least one market/bidding area, with Norway comprising three areas, whilst Finland, Western Denmark, Eastern Denmark and Sweden are singular areas. This division is important if the calculations of the transmission capacity between the areas, coordinated between the TSOs and communicated to Nord Pool, reveal congestions on the transmission network. In this case different spot prices for congested regions result. In the absence of any grid congestion then there is a unique system price throughout the whole Nordic region. Within all countries other than Norway counter-trading, including bids from local generators and/or consumers, is the first-choice measure to relieve transmission constraints.

The Nord Pool market combines the market segments of physical, energy-based spot markets with a financial market offering a portfolio of financial contracts. In addition, the timing and operation of these markets is partially integrated with the physical operation and balancing of the power systems (see Figure 28). More precisely, Nord Pool's physical day-ahead market Elspot, which clears at 12:00 pm on the day-ahead, not only allows market participants to close their trading positions and optimise their generation schedule, but also serves to allocate transmission capacity between the different market areas. The Elbas market, which starts in the afternoon of the day-ahead, allows market participants to further refine their positions by means of intra-day trading until one hour before real-time, including cross-border trading (subject to the availability of cross-border capacities). The residual balancing of the system is then performed by the four national TSOs, which mainly rely on the common Nordic 'regulating power market', or balancing market, for this purpose, alongside the use of other ancillary services. The price of balancing energy determines the price which market participants have to pay for their imbalances..

Figure 28: Mechanisms for Balancing the Power System (all Nordic Countries from 2009), Source: Description of Balance Regulation in the Nordic Countries, Nordel 2008.



Nord Pool Physical Markets

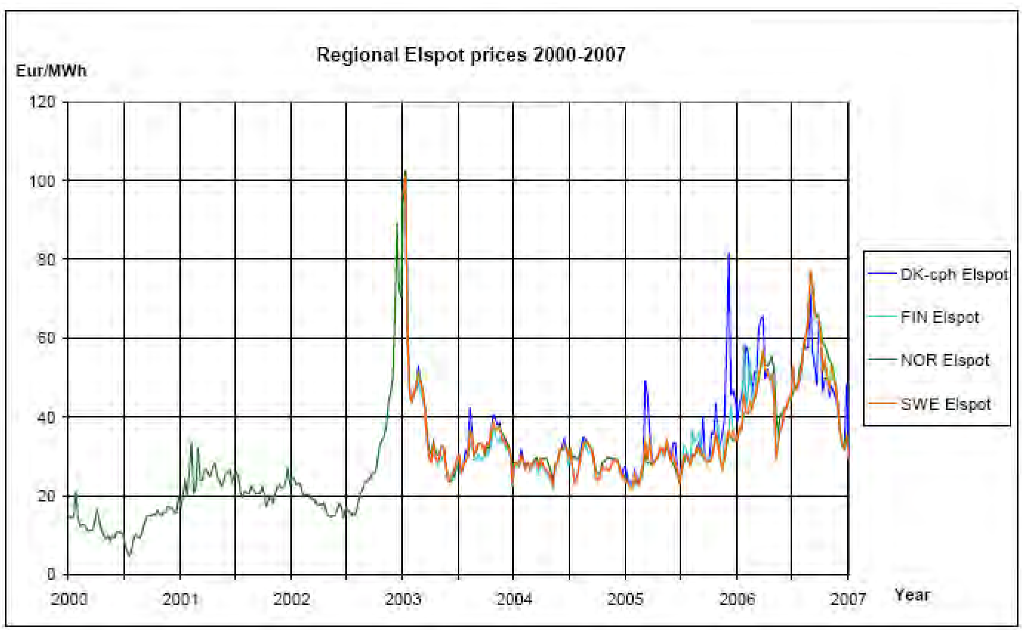
The physical market at Nord Pool is organized as a power exchange. Whilst participation in this market is in principle voluntary, there is a requirement for cross-country trades to be executed at the physical market of Nord Pool. This market makes a distinction between the day-ahead and the intraday market (Elbas and Elspot), which are described below. The importance of these markets is demonstrated by the trading volumes with trades at the Nord Pool spot market covering approximately 75% of total consumption in the Nordic region.

The Day-ahead market, called Elspot, gives market participants the opportunity to trade (single- or block-hour) contracts aimed at physical delivery on the following day. Elspot effectively consists of seven different market areas,[50] which are cleared in parallel with the allocation of cross-border capacities. The hourly market price is determined in an implicit auction as a function of the grid congestions forecasted and communicated by the TSOs, resulting in a common system price or separate prices for each area restrained. This implies that energy and capacity are traded simultaneously. Financial settlement is carried out on the basis of each participant's net trading volume.

In the-intra-day market (Elbas) market players from the Nordic region as well as from interconnection regions such as Germany may trade remaining transmission capacity and backhaul capacity from the day-ahead market. This market lasts from 36 hours out until up to one hour before planned delivery and deals with hourly contracts. In this market, as intraday trades may also have in impact on cross-border transmission capacity, the available capacity is continuously re-calculated.

The spot market can demonstrate substantial price differences between the market areas, for instance for almost 50% of the time in 2007 prices in Denmark differed from those in Southern Norway. For only 25% of the time there was a common system price over all market areas. This was due to volatility of hydro-production and specific generation and consumption patterns in each of the Nordic countries. An overview of the impact of this variation can be seen in the graph of regional Elspot prices provided below. However, this picture does hide the short term differentials in prices between periods.

Figure 29: Price History at Elspot by Region; Source: Study on cost-benefit analysis of Nordic retail market integration, VTT, 2008



[50] Whereas Finland and Sweden each represent a single market area, Denmark is divided into two and Norway into a total of three different market areas.

Financial Markets

On the Nord Pool Financial Market participants may hedge price risks from power procurement up to several years in advance, having at their disposal various standardized derivative instruments. Settlement is exclusively financial between Nord Pool's Clearing division and each trading partner. Futures and forwards contracts can be traded continuously. While futures transactions aim at short-term risk hedging by means of day and week contracts, forwards serve to minimize risks from long-term transactions, i.e. one month to several years.

Contracts for Difference help mitigate the risk that the spot market equilibrium price, being the reference price for future/forward contracts, turns out to be different from the market area price of spot market transactions. In addition market participants can also opt to engage in European-type options contracts based upon underlying standard forward contracts.

In addition to the Nord Pool financial markets there is also a significant OTC/Bilateral market. Covering 30% of total consumption in the Nordic market, bilateral contracts are an important flexible instrument for market participants as it allows them to agree on transactions equivalent to standard financial market products or specifically tailored to their needs.

Regulating Power Market and Balancing Rules

Frequency deviations and imbalances between generation and consumption are mitigated by a coordinated mixture of frequency-controlled regulation and manually activated regulation, which are agreed upon by all Nordic TSOs in the System Operation Agreement.

The fast acting frequency controlled reserves consist of around 600 MW of (Frequency Controlled) Normal Operation Reserve and around 1000 MW of (Frequency Controlled) Disturbance Reserve.[51] This is determined for the whole Nordic region and then distributed for procurement among all TSOs according to national consumption and market characteristics. In addition there are significant amounts of fast acting disturbance reserve (Spinning and non-spinning operating reserves – 15 minutes). An overview of the requirements for reserve is shown in the table below.

[51] Normal operation reserve caters for frequency deviations of +/- 0.1 Hz from the default value, while disturbance reserve refers to deviations down to 49.5 Hz.

Table 13 Reserve Levels in the Nordic Markets: System Operation Agreement 2009

Type of Reserve/ Country	Denmark	Finland	Norway	Sweden	Total
Frequency controlled normal operation reserve	23	139	207	231	600
Frequency controlled disturbance reserve	168	251	348	394	1161
Fast acting disturbance reserve	980	1000	1200	1200	4380
Total	1171	1390	1755	1825	6141

The manually activated reserves are procured by a common Regulating Power Market, where TSOs act as a single-buyer to procure reserves to cater for generation-consumption imbalances. All reserve suppliers (generators, demand side), that meet specific technical requirements, may bid at latest 1-2 hours before potential activation into a common Nordic regulation list, sorted by price and made available to all TSOs by the Nordic Operational Information System. TSOs coordinate the deployment of reserves form the list aiming at activating the most economic bids. Activated bids are paid the marginal price of all activated bids within the corresponding hour unless there are transmission constraints. If some area is affected by congestion, certain regulating bids will be disregarded from the common bid list and the regulating power price for that area will be different from the price of the other subsystems.

The national regulating power markets have continued after the incorporation of the common Regulating Power Market, although they reflect the fundamentals of the common market where bids from eligible providers are pooled from the national markets. Eligible providers have to meet certain technical requirements,, for instance having the ability for real time measuring and starting the facility with 10 minutes notice time and submitting bids between 10 MW and 500 MW which do not exceed a specific maximum price level. This implies that not all regulating power providers participating in the national market are eligible for the common Nordic market, or their admission may depend on the operating status of the facility of the provider. However, reserve providers not participating in the common market may be activated for the purpose of "special" regulation on a local level, which includes technical reasons other than balance regulation, e.g. congestion management. This would be remunerated by marginal price in Finland and according to the pay-as-bid principle in the other countries.

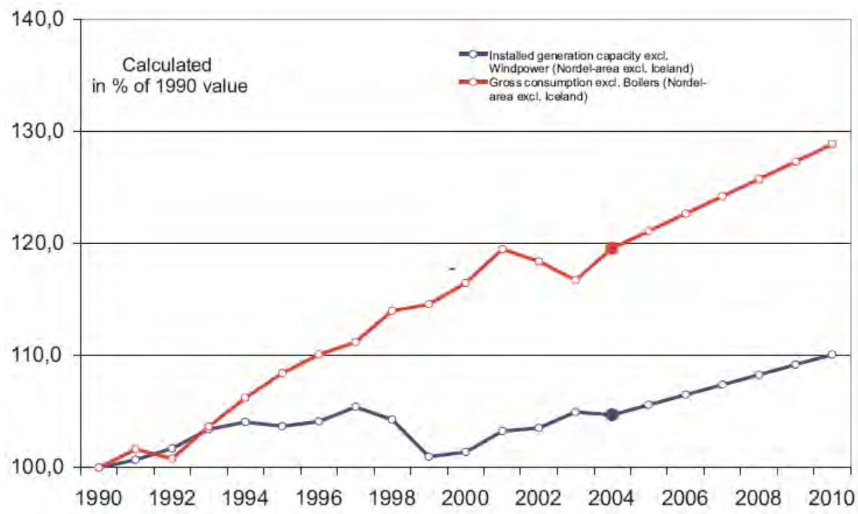
Balance settlement relies on a two-tier settlement mechanism. First, balance power is settled between countries (TSOs), according to the settlement rules defined by the Nordel System Operation Agreement. This agreement stipulates, imbalance responsibility, which means that participants who are responsible for system imbalances have to carry the burden of the TSO's cost of re-balancing. Settlement between TSOs and balancing responsible parties is then arranged in each country according to national balancing agreements. In some of the national markets the principle of asymmetric pricing of positive and negative imbalances is prevailing, which produces strong incentives for participants to be in balance.

Despite the common regulation bid ladder, there remain significant differences in balance regulation between the Nordic countries. Generally speaking, stipulations concerning bid requirements, bid schedules, pricing and settlement are defined nationally by the Nordel countries, which means that the reserve suppliers' access to the Regulating Power Market is still specified by national balancing agreements. However, there are ambitions towards a more harmonized market and Nordel countries have agreed upon new balance management principles that will become effective from 2009. The cover cost allocation, calculation and pricing of balance power and common fee structure, introduction of Elbas intra-day trading in all Nordic countries, separate balances for production and consumption and common gate closure.[52]

Generation and Supply Balance

The Nordic region has recently seen increasing consumption, both in general terms and during peak-times, with relatively low incentives to invest in new generation capacity. This has resulted in an increasing gap between installed generation capacity and consumption. Figure 30 illustrates this development resulting in an increasing probability of price spikes, supply failures, exploitation of market power and potentially disconnection of customer.[53]

Figure 30: Growing Gap between Installed Generation Capacity (blue) and Gross Consumption (red) in the Nordic region; source: Nordel, 2005.



52 See Description of Balance Regulation in the Nordic Countries, Nordel, 2008; Monitoring of the Nordic Regulation Power Market, NordREG, 2007

53 Developing Demand Response on the Nordic Electricity Market - Special print of the feature article in Nordel´s 2004 annual report, Nordel, 2005.

4.7.3 Specific Mechanisms aimed at Supporting Reliability and Security

4.7.3.1 Overview

The Nordic markets have chosen not to adopt any formal capacity mechanism. However, in the context of this increasingly tight generation/consumption balance the Nordic TSOs have developed and implemented different measures to ensure system reliability. These measures include:

- Regional Operating Reserve Capacity Markets in Norway and Denmark;
- Demand Response; and
- Peak Load Arrangements.

Each of these measures is explored further in the sections below.

4.7.3.2 Regional Operating Reserve Capacity Markets in Norway and Denmark

In Norway, for the procurement of manually-activated fast (15minutes) operating reserves the Norwegian TSO Stattnet uses a weekly options market for the procurement of sufficient reserves ("Regulerkraftopsjoner" RKOM) and a daily regulating energy market ("Regulerkraftmarked" RKM).

The RKOM market is run by the TSO Stattnet, which determines and auctions the capacity needed for a longer period of time. The tenders were introduced to minimize the risk of not satisfying the TSO's need for regulating power on the daily market RKM. Reserves are mainly contracted between November and March due to reduced availability of certain resources (e.g. water reservoirs) and higher demand during winter months. Initially, contracts had a duration of various months, which has been reduced to one week. Apart from producers, also consumers (mainly power-intensive industry) may participate in the tendering. Reserve providers must offer a capacity of at least 25 MW to the TSO and hold it available to the TSO's disposition during one week (Monday to Sunday, 5-23 h). The total reserve capacity contracted may be distributed among several units. The volumes reserved via the tender may vary considerably between seasons, depending on the availability and the water supply of hydro-power plants, and between regions as Norway is divided into three market regions. Reserve suppliers are selected based on the capacity asking price offered and are paid by marginal pricing, irrelevant of the real costs of power generation.

The capacity volumes contracted at the RKOM are included in the daily regulating power market RKM. Besides from the RKOM contracts also other suppliers of regulating power may bid into RKM, where power is procured to a scale of 2000 MW and which is remunerated only based on the energy activated. Hence, activated bids from the RKM which were previously contracted on the RKOM receive separate capacity and energy payments. Today, RKOM is also open to participation of suppliers from other Nordic countries. There is already limited engagement of suppliers from Western Denmark. [54]

In Denmark, the TSO has a similar approach, but instead uses negotiated tenders and a prequalification process to select potential reserve suppliers and to acquire sufficient manual regulating power from them. The TSO enters into long-term and monthly agreements. Against a negotiated fixed payment for reserve holding during contract duration, reserve providers are obliged to submit regulating power bids of a previously defined nature to the daily regulating power market. Alternatively, regulating power providers may decide not to enter into a fixed agreement with the TSO, but instead to place bids into the daily market spontaneously and without any contractual restriction. The bids to the regulating power market are included into the common Nordic Operational Information System. It should be noted, that procurement can differ between Western and Eastern Denmark. Moreover, the total amount of reserves tendered may vary seasonally and procurement via long-term and short-term contracts may not consider upward and downward regulation to the same extent.

4.7.3.3 Demand Response[55]

Demand Response (DR) is defined as a voluntary adjustment of electricity consumption, with positive effects on the demand-offer balance, security of supply and lower overall electricity procurement costs. Demand Response may be driven by market price for electricity which signals to the consumer when to realise electricity cost reductions. Accordingly, Demand Response's main goals are to reduce consumption when there is a negative marginal benefit from consuming electricity and to defer it to periods with lower electricity prices. However, there is also the option of increasing demand in situations of low prices, e.g. pump-storage plants' demand for base-load electricity from plants with must-run constraints during off-peak hours. The price signal may come from real-time market prices or a flexible tariff structure with time-of-use or power demand-fee elements. The demand response may also include the strategies of bidding of demand reduction or re-selling of electricity into the market.

Alternatively, Demand Response may be used as a contractual reserve service, for instance for real-time balancing, as disturbance reserve or peak load reserve. This service is offered to the system operator against additional payments based on the reserved capacity, the delivered energy, the time availability, contract duration etc. This reserve may be activated when needed, either manually by the system operator or automatically, and thus contribute to system stability and balancing of demand and generation in real-time. In contrast, load shedding is forced due to serious frequency deviations from default value and is therefore not interpreted as demand response.

54 Stattnet's Reserves Option Market, Bjorn Walther, Stattnet, 2005; Provision of operating reserve capacity: Principles and practices on the Nordic Electricity Market, MPRA, 2007.

55 Demand Response as a resource for the adequacy and operational reliability of the power systems - Explanatory Note, ETSO, January 2007; Enhancement of Demand Response, Nordel Demand Response Group, 2006.

The Nordic countries have already stipulated demand side incentives, both price-driven and contract driven to help ensure reliability. Electric boilers, either working with electricity or oil, with a total installed capacity of some 2000 MW and a demand of some 10 TWh per year are attributed a significant demand response (200-300 MW in Finland, 500-1000 MW in Norway and 700-1000 MW in Sweden). In addition to that, customers disposing of electrical and carbon-driven boilers may profit from reduced tariffs in a similar way to interruptible customers.

In principle, consumers offering DR may become active on several of the Nordic markets including:

- Nord Pool financial market;
- Elspot day-ahead market;
- Elbas intra-day market;
- Frequency controlled reserves and manual fast active reserves; and
- Regulating power market.

However, in practice the appearance of DR on these markets has been quite diverse. On the financial market and the intraday market there are currently no products tailored to the needs of DR and there is some doubt on whether DR providers have a real interest in trading on this market. Reasons might be obstacles related to the production process (costs, risks and inconveniences of short-term adjustment / pausing the production process), lack of knowledge on the economic opportunities of DR, and lack of motivation, e.g. to build up a trading department. Additionally, consumers have not clearly and uniformly signalled their interest in new financial/ physical trading products as few price spike situations have been observed, and heterogeneous demands on peak products may harm its liquidity. On the day-ahead market the picture is similar except for Norway, where large industrial consumers have been increasing their DR engagement.

On the reserve market TSOs have contracted DR as frequency controlled reserves, but to varying degrees. In Denmark, Norway and Sweden there were no provisions for the engagement of DR as frequency controlled disturbance reserves in 2006, while Finland had in mind to extend DR from 120 MW contracted from 2006 – 2008 to 200 MW in 2009.

In the case of fast acting reserves, the Norwegian RKOM (see above) has proven to be a model for absorbing DR offers. In contrast, DR did not play a significant role in Denmark and Sweden in 2006.

A summary of the potential of DR in each of the market along with how it is currently used is shown in the table below.

Table 14: Demand Response Resources Contracted by Nordic TSOs by 2007

Country	Technical potential	Currently contracted	Estimated activation price paid/ to be paid
Denmark	380 MW	- 53 MW fast active disturbance reserve (50 MW of back-up generation (pilot project) plus 3 MW in Eastern Denmark)	-
Finland	1280 MW	545 MW (frequency controlled disturbance reserves (120 MW), fast active disturbance reserves (425 MW)), with the option to be extended.	Approx. 300 €/MWh
Norway	- Temporarily > 1480 MW on RKOM market; - 500 MW by aggregated back-up generation - 1000 MW of electric boilers	- 1480 (Maximum weekly acquisition on the RKOM market); additionally; - 370 MW by bilateral contracts with single big customers; - Consideration of small costumers/retailers by aggregated DR bids (pilot project)	100 – 400 €/MW (Weekly premium at RKOM during 2005/2006)
Sweden	e.g. 870 MW offered for 2005/ 2006	- 90 MW fast active disturbance reserves; - 503 MW peak load resources for 2006/2007	-

4.7.3.4 Peak-Load Arrangements

Peak Load Agreements are legal stipulations to make sufficient peak load reserve (generation capacity and/or consumption reduction) available especially, during winter times and, hence, guarantee security of supply. An additional intention of these non-market-based provisions is to shelter consumers from high and volatile market prices, which may result from temporary or seasonally reduced availability of water reservoirs for hydro power production. Finally, they may protect national power production facilities and help maintain the existing power production peak.

According to the Nordel System Operation Agreement, peak load resources are defined as reserve with long readiness time and aimed at mitigating shortages during times of high load. In the case of more accurate demand forecasts, this preparation time may be reduced sufficiently so that peak load resources may be available either day-ahead on the spot market, or via the regulation reserve market for the day of operation.

Currently, only Sweden and Finland have the legal basis to allow the TSO to procure peak load resources In Finland, a law, which came into force in 2006 and will not expire before 2012, requires mainly carbon-based power plants with low usability and meeting legal requirements to provide their capacity to the market during winter peak times instead of being decommissioned. The Finish TSO is in charge of managing the peak load arrangement, passing the costs for generators' compensation through to grid users by means of special charges. In Sweden, the TSO has to procure an additional 2000 MW peak load reserve from consumers and/or generators (share of 500 MW), bidding into the spot or the regulating power market. Further provisions specify also when and how reserves may be activated by the TSO. Current legislation stipulates the peak load reserve system at least until 2011 and may be phased out only by 2020.

Such agreements are likely to impact on the Nordic power market. Potentially they could enlarge the offers on the spot and /or regulating reserve market, bring down market prices, replace other generation sites which may not be competitive at falling prices and give consumers incentives for expanding their electricity use. However, not making these peak load sources available may risk security of supply. This comes along with rising prices which may stimulate balancing responsible parties to gamble on their daily schedule balance connected to risks for high imbalance settlement charges. Moreover, the TSO may then face the risk of not being able to cover resulting real-time imbalances by the regulating market.

Both, Nordel and the Nordic Energy Regulators agree that current peak load agreements need harmonization and should be replaced by a pure market solution. More specific, Nordel has proposed a transitional solution, although this is not totally in line with Nord Energy Regulators' views. However, both agree that peak load agreements should be used only when security of supply may not be guaranteed without them and should be designed in such way that negative effects on the spot market are minimized.[56]

4.7.4 Experiences to Date

The Nordic Power Market is the first multinational integrated electricity market worldwide. Since the start more than 10 years ago it has been performing well and has been continuously refined. The increasing level of transmission links between Nordic countries and its modernization have been conducive to balancing the diverse generation and consumption structure in the Nordic countries and to facilitate increasing electricity trading in the region. Growing cooperation between national TSOs and interconnected electricity networks, especially UCTE, has also stabilized the network and contributed to continued security of supply.. The integrated Nordic Power Market has led to price stability/moderate price increases, compensation of seasonal and structural differences between countries, substantial procurement cost reductions for electricity and security of supply, within the Nordic region and partially also beyond the region.

[56] See "Guidelines for Implementation of Transistional Peak Load Arrangements", Nordel, February 2007; „Peak Load Arrangements – Assessment of Nordel Guidelines", NordREG, Report 2/2009.

There are currently a number of challenges facing the Nordic markets. This includes the integration of rising wind energy production, the dependency from hydro production, climate-based volatility of production from hydro power and heating consumption, congestions due to rising scales of cross border electricity trading and increasing consumption. In addition there is concern on security of supply in terms of energy and capacity. There is still an need to close the gap between generation and consumption opened in the first years of this decade when consumption rose continuously, production facilities declined, and the Nordic regions eventually became a net importer of electricity.

In order to tackle these challenges, the Nordic region has relied on an approach which combines infrastructural measures with market-based measures. The infrastructural part combines the expansion of production capacity, cross border transmission lines and interconnections to adjacent networks. The market-based part refers to the common Nord Pool market and common market rules. An example is harmonization and standardization, for instance in regards of balance settlement, regulating power market rules, retail market integration, metering and data management.[57]

After the experience of the extreme price spikes in the winter 2002/ 2003 (see section 2.5.1) the Nordic countries have derived a set of preventive counter-measures, for instance re-vitalizing mothballed units by means of peak load arrangements, promotion of price-elastic consumption (demand response, increased frequency of consumption data meter reading, price-indexed electricity contracts) and the expansion of the Elbas market segment to all Nordic countries and other countries. However, it should be noted that these measures do not fit optimally into the current market structure. Peak load arrangements may distort market performance and are only transitional, and potential suppliers of demand response may not find the right products or adequate price spike situations to place their offer.

Despite the exceptional situation in 2002, Nord Pool prices, in general, have been quite stable and have not served to give right investment incentives for new peak load production facilities. This has resulted in relatively small investments in new production capacity in the past and stresses the need for future investments to cope with raising consumption. In addition, investments in new production capacity compete with reinforcement efforts in transmission lines and interconnections, and incentives to increase the demand side's engagement during peak load situations.

In its latest energy and power balance forecast for 2012/2013, Nordel estimates that there will be additional 7500 MW of production capacity available by the end of 2012. According to this forecast, Nordel concludes that the Nordic region will have a balanced energy balance during normal weather conditions, even without imports. There is a risk that low inflow/precipitation conditions may require additional imports from neighbouring countries and may expose some Norwegian areas to the risk of rationing. However, the Nordic power system is assumed to be able to cope with peak demand situations

[57] Nordel Annual Report 2003, p.18-25.

both at average winter temperatures and during extremely cold periods, which are assumed to occur once every ten years.[58]

58 See "Power and Energy Balances 2012-2013", Nordel, June 2009.

5. Observations and Conclusions for AEMC Consideration

This section divides into 3 parts.

- The first part provides a summary of the market models including the key features and the issues that may be faced with their implementation;
- The second section summarises the 6 key markets that were examined (with the NEM as a comparator) and the mechanisms they use to promote reliability and security of supply. It also considers the practical issues that the countries have encountered in implementing these mechanisms; and
- The final section pulls together some key conclusions that may be applicable to the National Electricity Market.

5.1 Summary of Market Models

The following table provides a summary of the different market models that could be applied and issues faced. It is important to recognise that these are not all mutually exclusive and that some of the models are applied in combination i.e. demand responses is often a key part of many other schemes.

Table 15: Summary of Alternative Market Model Features Designed to Enhance Reliability and Security of Supply

Model	Key Features	Key Issues
Capacity Market (traditional)	Volume obligations placed on retailers, to be met by purchases of certified volumes from generation	Not clear that security of supply at system peak is enhanced. Some volatility in energy markets may be ameliorated. High transaction and administrative costs.
Reliability Options	(Financial) Call options for forward energy	Strong incentives to make capacity available at time of peak load. Effective hedge against price spikes. High transaction and administrative costs.
Peak Load Reserves	Control and operation of selected peaking plant by the System Operator	Security of supply may be enhanced in the shorter term, but long-term efficiency may be compromised. Concerns about System Operator competing in market. Limited costs.
Operating Reserves Pricing	Market-based procurement and pricing of operating reserves	Focus on security rather than adequacy. May provide additional income to peaking plants. May promote short- and long-term efficiency. Limited costs.

Model	Key Features	Key Issues
Capacity Payments	Capacity pricing alongside energy pricing, based either on costs or value of such capacity	Not clear that security of supply at system peak is enhanced. No incentives for efficiency. High costs.
Long-term Bilateral Contracts	Use of long-term bilateral contracts	Provides for efficient hedge against uncertainty but unlikely to function on a voluntary basis. Promotion of short-term efficiency. Barriers to entry impair long-term efficiency
Demand-Side Short-Term Pricing	Demand response to (tariff) pricing	Supports reliability / adequacy but unlikely to be sufficient on its own. Facilitates efficient outcomes for scheduling and dispatch. May reduce costs
Interruptible Load	Demand response to instruction, or automatically, as a form of Operating Reserve	Supports security but unlikely to be sufficient on its own. Facilitates efficiency of reserve provision. May reduce costs

To provide for a more structured view, Table 16 provides a simplified evaluation of the four different models and their relevant variations against the different criteria defined in section 3.1. This comparison allows for the following observations:

- Only the first two or three of the models are likely to directly ensure that the desired reserve margins will be met. However, all of these first three models also have some significant disadvantages, including the creation of barriers to entry (1 – 3), the lack of incentives for maximising output and the risk of manipulation (1), high complexity and costs (1, 2) or concerns related to the long-term efficiency of the mechanism (3). In a direct comparison, the concept of traditional capacity markets furthermore appears as being generally inferior to reliability options.

- Price-based mechanisms (5) may not succeed in assuring reliability. Moreover, capacity payments are unlikely to result in an economically-efficient outcome.

- Whilst short-term bilateral contracts have obvious advantages, we are not convinced about the case for voluntary long-term agreements (6) for peaking plants. Conversely, any mandatory requirements would likely impair long-term efficiency and create serious barriers to entry.

- Demand-side measures (7, 8) generally increase economic efficiency, are fully compatible with the basic market design and come at limited costs. However, they are unlikely to ensure reliability on their own.

- Market-based pricing of operating reserves seems likely to show a good performance in almost all of the criteria considered. However, it focuses on security rather than adequacy such that it is not clear that reliability will be enhanced.

Table 16: Simplified Assessment of Alternative Market Models

Criteria for Evaluation	Quantity-based mechanisms						Demand-side measures	
	Capacity Market	Reliability Options	Peak load Reserves	Operating Reserves pricing	Capacity Payments	Long-term Bilateral Contracts	Short-term pricing	Provision of operating reserves
	1	2	3	4	5	6	7	8
Reliability and security of supply								
Ensure reserve margin	+	++	(+)	(+)	0	-	(+)	(+)
Maximise output during scarcity	0	++	++	+	0	++	+	+
Economic efficiency								
Long-term	(+)	(+)	(+)	+	-	-	+	(+)
Short-term	0	++	+	+	-	++	+	+
Costs	--	--	+	+	--	?	++	++
Compatibility with market design	+/-[(a)]	+/-[(a)]	-	+	+/-[(a)]	--	++	++
Barriers to entry	-	-	--	+	+	--	+	+
Feasibility (complexity)	--	--	0	+	0	+	+	+

Evaluation: ++ - Very good; + - Good; (+) – Generally good, with some reservations; 0 – Mediocre; - - poor; -- - very poor; ? - questionable

[(a)] – Markets with centralised / decentralised scheduling

5.2 Summary of International Markets

This table provides a summary of the mechanisms used in different markets to provide reliability and security of supply

Table 17 Summary of International Markets

Market	Models Applied	Evidence to date
NEM	Energy only market with restrictions on maximum prices set high to allow achievement of reliability standards.	Reliability standards assessed over the longer term have been met in all regions. There has in recent years been increasing price

Market	Models Applied	Evidence to date
	Financial markets allow for longer term contracting and system operator can enter into reserve contracts in specific circumstances. Market has been designed to include Demand side participation.	volatility and prices have increased from historic lows. This has seen increased amounts of generation being proposed and commissioned.
PJM	Capacity market includes rules for calculating generating margin requirement with encouragement for demand side participation	The initial capacity market in PJM suffered some problems. However, a new capacity auction was implemented in 2004. This has seen greater volumes of capacity procured including significant demand response.
NYISO	Capacity market established with rules for calculating the required generation requirement and for determining the level of unforced capacity that each generator contributes.	Initial implementation of the capacity market saw large price variations even when there were only small variations from the capacity target, although subsequent changes stabilised the price and revenue streams. However, there is concern on market power in constrained zones and that the capacity market has not stimulated new resources as the capacity margin is shrinking.
BETTA	Left to the market with information provided to stimulate investment. In addition introduction of demand participation and active market procurement of reserves (with incentives on the procurer to reduce costs)	Heavy consolidation and vertical integration to-date. No significant events so far. Large queue of new generation set to come on stream in next 10 years in response to emissions targets, EU legislation, Government fuel diversity policy and market conditions.
SEM	A number of mechanisms exist principally capacity payment schemes but also demand side management scheme and ancillary services that help with security of supply.	Relatively recent market opening means limited evidence yet on the success of the capacity mechanism. Demand side management programmes have been run with some success to improve supply security.

Market	Models Applied	Evidence to date
Western Australia	The Principal scheme in Western Australia is a capacity market. In addition there is the provision of operating reserve and the ability for the demand side to participate in the Capacity Mechanism.	The capacity mechanism has been successful in procuring excess levels of capacity in each of the last 4 years with strong investment across all fuel types, although there is some concern on the level of investment of plant with dual fuel capability. There is now sufficient capacity entering the SWIS to meet projected demand until the 2014/15 period.
Nordic Countries	1) Peak load arrangements in Sweden and Finland; 2) Forward contracting of operating reserves; 3) Specific arrangements to incentivise demand-side provision of operating reserves (in Norway); and 4) Partial use of short-term pricing for consumers	Although the Nordic electricity market is generally considered a showcase of successful liberalisation, the 'temporary' introduction of peak load arrangements in Sweden and Finland is a clear sign of concerns about long-term reliability in a hydro-dominated system. Whilst demand-side participation has been highly successful especially in Norway, it has to be seen in the light of the specific consumption structure, with a high proportion of energy-intensive industry and the wide-spread use of electric heating; consequently, the potential in the other Nordic countries is being regarded as much lower than in Norway.

5.3 Conclusions

This Section provides a number of key observations and conclusions which KEMA assess to be of particular relevance to the AEMC and the prevailing market context in Australia;

1) None of the alternative market models discussed seems to be perfect in a sense that it fully satisfies all of the criteria defined above.

2) In particular, only very few models are likely to provide a reasonable ‘guarantee’ of actually being able to assure reliability. This advantage however comes at the expense of a possible deterioration of long-term efficiency and/or significant costs and complexity of the mechanism.

3) A comparison of international markets, including those specifically considered in this report, shows that the mechanisms focusing on the promotion of generation adequacy, i.e. some form of capacity obligations or capacity payments, are more commonly found in centralised pools than in bilateral markets. Amongst others, this is related to the issue of measuring the availability of generation to the wholesale market, which is a crucial precondition for many of the market models considered in this report.

4) Some of the markets now have many years experience of continuing to operate successfully in providing security and reliability of supply. Others have exhibited periods of high prices, but this may be due to input costs and availability (e.g. high fuel prices, shortages of water) as much as the inability of the market to provide sufficient generation capacity. Most importantly, there does not seem to be a clear relation between the application of specific capacity mechanisms and improved reliability, and vice versa.

5) Although demand-side measures can only support reliability, at least some potential may possibly be made available at limited costs. If these measures are limited to specific large customers, then they are less difficult to implement than a full market design and can improve efficiency without presenting any additional barriers to entry for generators. However, the potential for demand-side measures strongly depends on the specific consumption structure of a given market, whilst the general application of demand-side measures to all consumers may result in significant costs and complexity.

6) Similarly, the market-based procurement/deployment and pricing of operating reserves generally shows a positive performance against most of the criteria defined above. The main disadvantage of this model is related to the fact that it provides only an indirect way of promoting reliability. However, the proposal of an ‘operating reserves pricing’ model with a (partial) purchase of excess operating reserves may offer an improved performance in this respect.