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Loads Providing Ancillary Services: Review of International Experience

Technical Appendix: Market Descriptions

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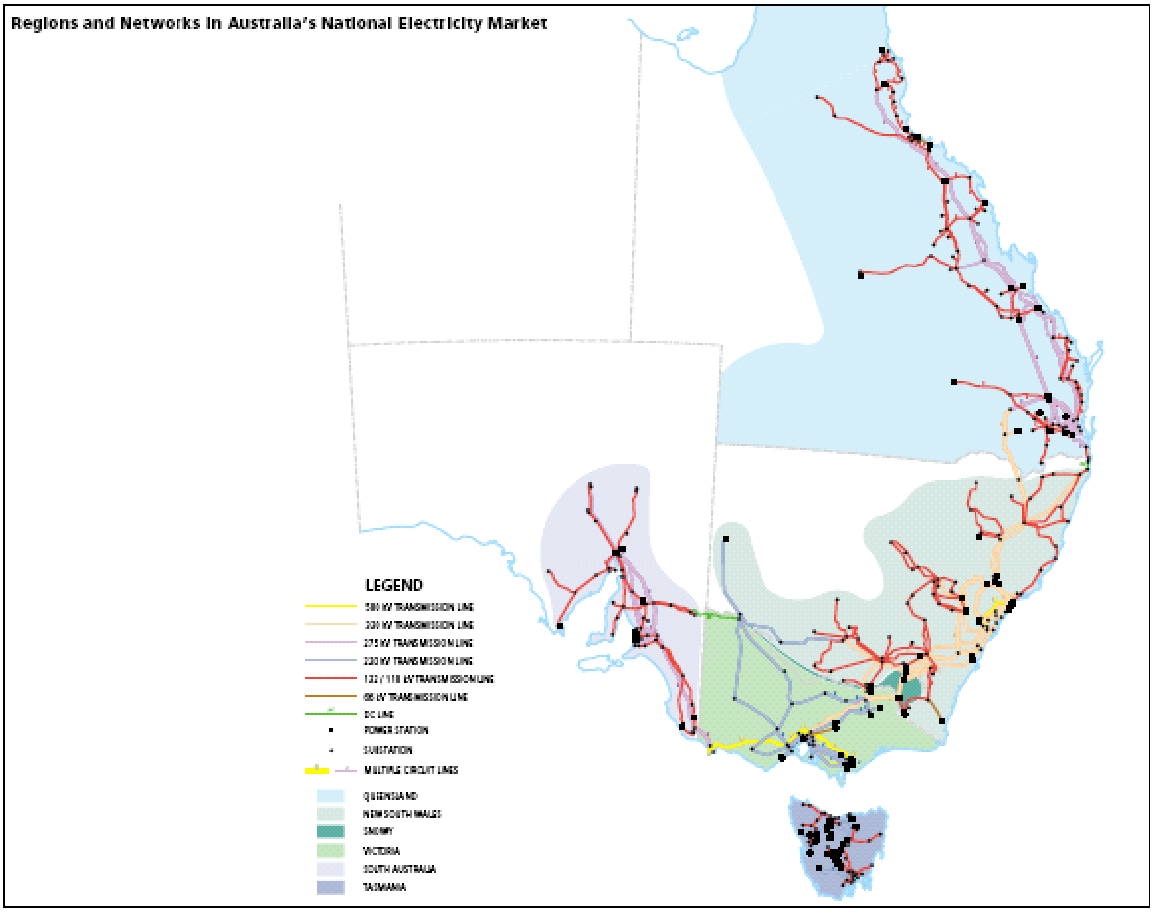
Table of Contents

List of Figures

List of Tables

A. Australia's National Electricity Market: Ancillary Services and Load Participation



A.1 Australia's National Electricity Market: Overview

Since 1999 the National Electricity Market (NEM) has been the wholesale market for supply of electricity to retailers and end-users in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. Tasmania joined the NEM as an independent region in July 2005, and was physically connected to the mainland transmission network in April 2006 with the commissioning of the Basslink submarine DC power cable. The NEM operates the world's longest interconnected power system – more than 4000 km from northern Queensland to South Australia (see Figure A-1). Peak demand in 2005 was 31,000 MW and installed capacity was 40,100 MW [NEMMCO 2005a]. The value of electricity traded in the NEM exceeds A$7 billion (US$5.3 billion) per year in order to meet the demand of eight million end-use consumers. Weekly trade in the summer months may have value of up to A$500 million, requiring participants to manage the risks associated with trading in a market where the spot price is typically less than A$40/MWh but may range as high as A$10,000/MWh.

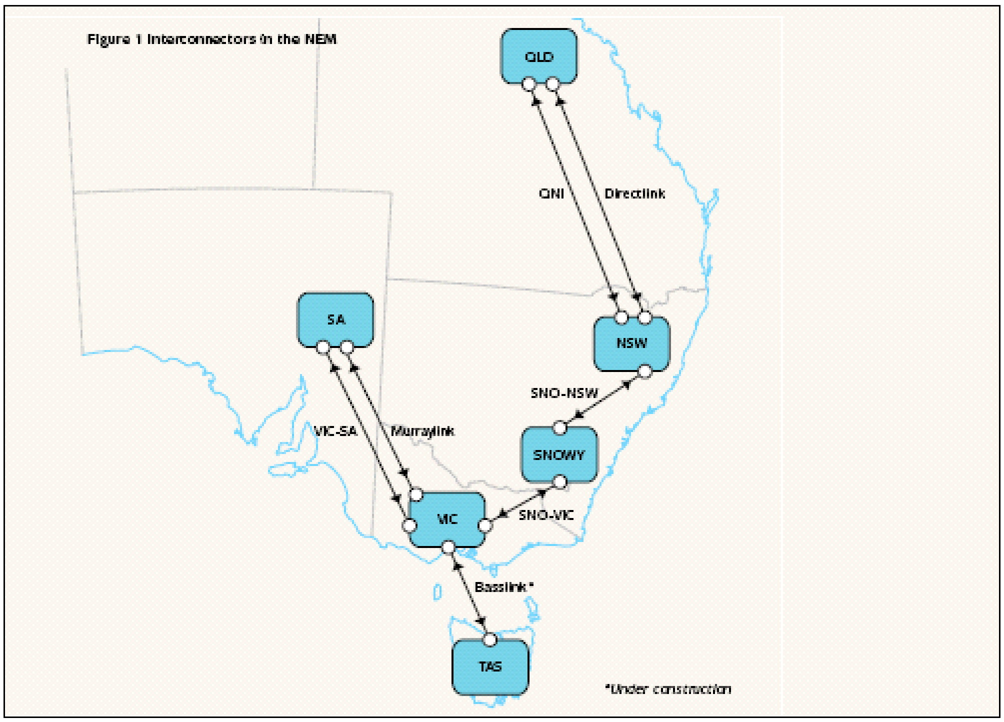


Figure A-1: Regions and Interconnections Comprising Australia's National Electricity Market [NEMMCO 2006a]

Figure A-2 shows the institutional framework for the NEM. Ownership of the NEM's infrastructure is mixed, with both public (State government) and private ownership. The National Electricity Market Management Company Limited (NEMMCO) was established in 1996 as both market operator of the NEM and system operator of the interconnected Australian power grid.[1] The participating state and territory governments own NEMMCO.

[1] Large portions of Australia will likely never be interconnected due to the distances involved. The Western Australia grid serves one million customers but operates as an independent integrated power system.

The National Electricity Rules (Rules) govern the operations of the NEM and specify the responsibilities and obligations of NEMMCO and all market participants.[2] The Rules provide the basis for regulating market operations, providing for power system security, maintaining resource adequacy, specifying conditions for network connection and access, and pricing for network services - all in such a way as to facilitate competition and supplier choice, provide open access to transmission and distribution networks, and guarantee equal and fair treatment amongst market participants, fuel type, and technologies. Effective July 2005, the Australian Energy Regulator (AER) and the Australia Energy Market Commission (AEMC) have taken responsibility for administering the Rules. The AEMC is responsible for: (i) administering the National Electricity Rules; (ii) undertaking any new rule-making required; (iii) reviewing market and system operations, and (iv) providing policy advice to the Ministerial Council on Energy. Individual State regulators determine the details of retail service and prices while the ACCC (Australian Competition and Consumer Commission) ensures that any potentially anti-competitive behavior necessary for efficient power system operations is minimized and authorized.[3]

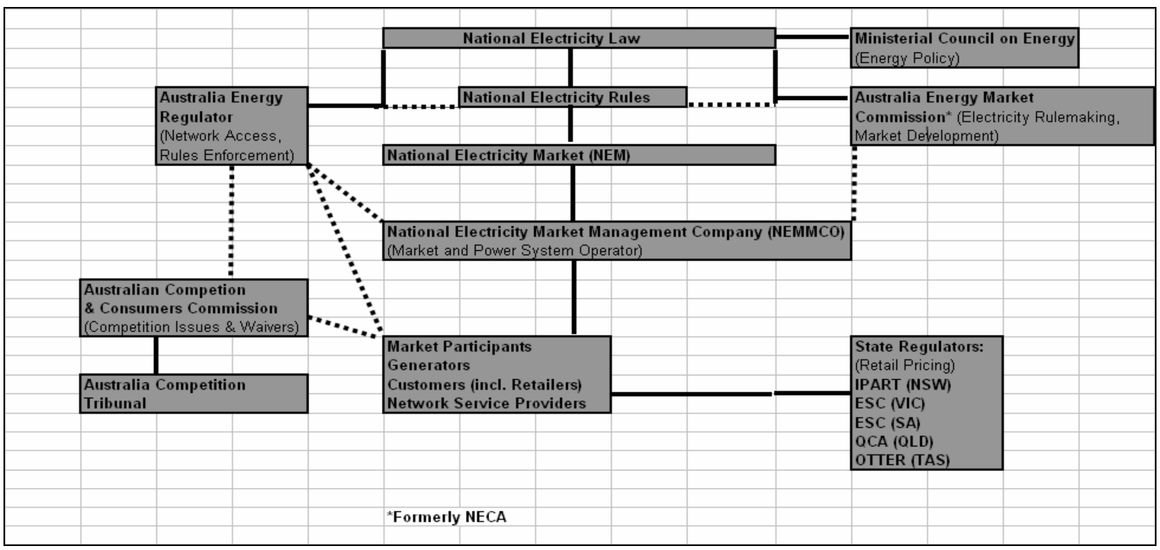


Figure A-2: Institutional Framework for Australia's NEM [NECA, 2005c]

A.2 NEM Market Design and Operations

Participants in the National Electricity Market engage in three types of physical and financial trading:

- Spot trading of energy through a commodities-type pool, with prices determined every five minutes by the last (most expensive) generating unit(s) or schedulable demand resource(s) selected to run. In the day prior to dispatch, Market Participants submit bids and offers with firm prices and estimated volumes. The market dispatch engine

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[2] The Rules, which in 2005 replaced the predecessor National Electricity Code, were the product of consultation and trials conducted between governments, the electricity supply industry and electricity users.

[3] State regulators include the Independent Pricing and Regulatory Tribunal of New South Wales, the Essential Services Commissions of Victoria and South Australia, the Queensland Competition Authority, and the Office of the Tasmanian Energy Regulator.

then calculates spot prices, dispatch targets for the energy market, and provides instructions for the frequency control markets, all at five minute intervals.
- Bilateral long-term derivative contracts covering (usually) fixed amounts of energy over specified time periods at predetermined strike prices.
- Short-term derivative trading, in which purchasers lock in energy prices through hedging contracts ("contracts for differences"), call options or more complex derivative products.

Market Participants include Generators, Network Service Providers, and Customers (Retailers and End-Users):
- *Market Generators* sell their entire electricity output through the spot market and receive the spot price at settlement. Scheduled Market Generators must be larger than 30 MW, while Non-scheduled Market Generators are smaller or have intermittent production characteristics (e.g., wind generating units).
- *Market Network Service Providers* (including Transmission Network Service Providers and Distribution Network Service Providers) own and operate networks linked to the national grid. They pay market participant fees and obtain revenue from trading in the NEM.
- *Market Customers* purchase electricity supplied to a connection point on a NEM transmission or distribution system for the spot price.
- *Electricity Retailers* buy electricity at spot price and retail it to end-users.
- *End-use Customers* buy directly from the market for their own use.

Prices for electricity are calculated for each five-minute dispatch interval and are averaged every half-hour to determine a regional spot price for each of the NEM's five regions.[4] Regional (zonal) reference prices are simultaneously determined and then adjusted for static losses to determine a price for each connection point at which there is at least one market participant. Thirty minute average spot prices as determined by NEMMCO are the basis for financial settlement. The Rules set a maximum spot price of A$10,000 per megawatt hour. This price cap is derived from a consideration of when customers would be willing to forego electricity rather than paying a higher price, and is thus called the Value of Lost Load, or VoLL. The VOLL is automatically triggered when NEMMCO directs network service providers to interrupt customer supply in order to keep supply and demand in balance.[5] It was triggered twice (8 March 2004 and 14 March 2005) over the 2004-2005 period (NEMMCO 2006b).

The NEMMCO is the overall system operator and is fully accountable for all aspects of system operations. NEMMCO system operations encompass several subsidiary organizations charged with planning and operating the NEM (see Figure A-3). NEMMCO operates redundant National Dispatch and Security Centers (NDSC) in Sydney and Brisbane. The NDSC coordinates operations of five Transmission Network Service Providers - TransGrid (New South Wales), ElectraNet SA (South Australia), PowerLink (Queensland), SPI PowerNet

[4] Limits on inter-connector capacity contribute to spot price differentials between regions.
[5] The VoLL serves two purposes: signaling customers when they should be indifferent to paying high prices or suffering interruption, and signaling Generators when they should undertake new investment.

(Victoria), and TranSend Networks (Tasmania) - each of which in turn coordinates the subsidiary operations of Distribution Network Service Providers (DNSPs) in their region.[6]

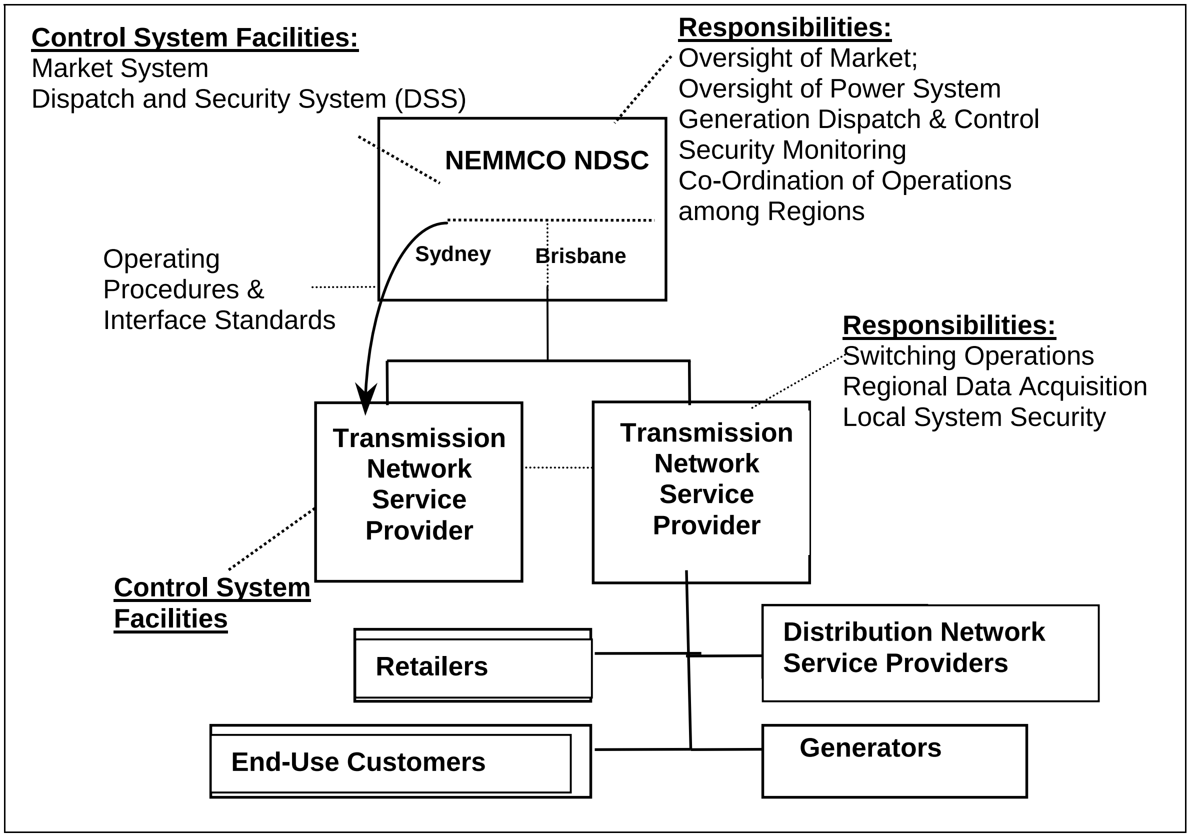

Figure A-3: NEMMCO's System Operations

Operators in the NDSC forecast system conditions, determine ancillary service requirements, issue unit dispatch instructions, and monitor for conformance with reliability and the Rules. The National Electricity Market Dispatch Engine (NEMDE) co-optimizes and dispatches ancillary services, prepares & updates weekly the ancillary services bids received and the pre-dispatch schedule, and coordinates and schedules loads on a real-time basis (see Figure A-4). Scheduled generators submit three types of volume and price bids for both energy and frequency-controlled ancillary services (FCAS): daily bids (submitted before 12:30 pm on the day ahead), re-bids (submitted up to five minutes prior to dispatch) adjusting the volume but not the offer price, and default, or standing, bids reflecting the base operating levels for generators.

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[6] Web sites are available for each TNSP: http://www.electranet.com.au/, http://www.powerlink.com.au/, http://www.transend.com.au/, http://www.transgrid.com.au/, and http://www.spipowernet.com.au/

NEMMCO's planning and operations must conform to the statutory National Electricity Rules. The Rules establish a Reliability Panel, whose role is to determine power system security and reliability standards and determine guidelines and policies for NEMMCO's exercise of its power to provide for sufficient reserves. NEMMCO is obliged to publicly call for competitive tenders for the provision of reserves, if any region is forecast to have a reserve shortfall within a 2-6 month period. The Rules also require NEMMCO to issue an annual Statement of Opportunities assessing the future need for electricity supply capacity, the status of demand side participation, and any transmission network augmentation needed to support NEM operations. The AEMC chairs the Reliability Panel and is required to issue an annual review of the performance of the electricity market from the standpoint of reliability and security [AEMC 2005].

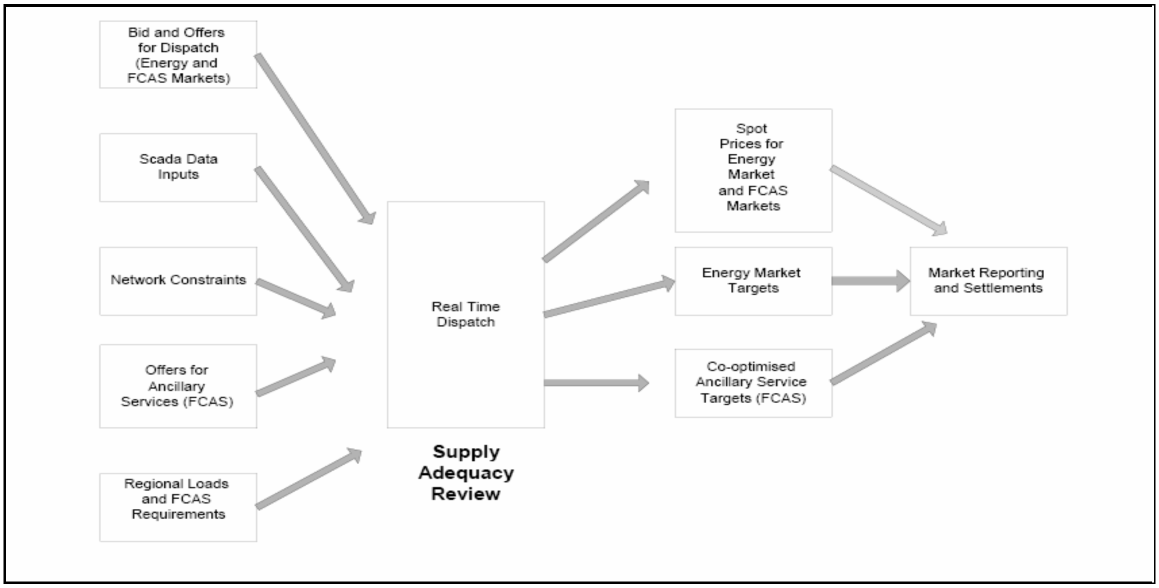

Figure A-4: NEMMCO's Real Time Dispatch Process

Table A-1 summarizes markets and network services managed by NEMMCO, including physical size, approximate turnover, and provision and modality for demand side participation. The first column provides the comparable North American wholesale electricity market corresponding to each NEM market or service. The operations of the non-energy markets and services are described in detail in the following sections.

Comparable North American Electricity Market	Equivalent Australian Markets and Service Requirements	Size/ Requirements (MW)	Annual Market Throughput	Criteria for activation	Does load participate?
Energy	**Energy** 1. Spot trading	176,144 GWh (2004-5)	A$ 7 billion (NEM 2004-5)	N/A	Yes, through retail subscription or as a Scheduled Market Load
	2. Forward contracts				
Regulation	**Regulation Frequency Control AS** 1. Regulating Raise 2. Regulating Lower	Mainland: 130 MW, 130 MW Tasmania: 50 MW, 50 MW	A$ 3.3 million (NEM 2004-5)[7]	Frequency deviation from nominal.	No
Under Frequency, Under Voltage, and Manual Load Shedding	**Uncompensated Load Shedding**	All energy Market Customers are obliged to provide automatic interruptible load to a minimum level of 60 % of their expected demand.	N/A	Loads would be progressively disconnected in accordance with under-frequency conditions Under-frequency Trip (according to under-frequency relay settings)	Yes, as participation is compulsory for Market Customers

[7] The global requirement for regulating FCAS has been progressively reduced from 250 MW (30 Jun 03) to 130 MW (1 Apr 05). This was accompanied with a commensurate reduction in payments for regulating FCAS.

Comparable North American Electricity Market	Equivalent Australian Markets and Service Requirements	Size/ Requirements (MW)		Annual Market Throughput	Criteria for activation	Does load participate?
Spinning Reserves (synchronized)	**Contingency Frequency Control AS** 1. Fast Raise (≤6 sec) 2. Fast Lower (≤6 sec)	Mainland: 350 MW raise & approx 100 MW lower[8]	Tasmania Approx 60 MW[13]	A$ 8.5 million (NEM 2004-5)	When the local frequency changes above or below the tighter limit of the normal operating frequency band	Yes; a Market Load registered as a market ancillary service.
	Contingency Frequency Control AS 3. Slow Raise (60 sec) 4. Slow Lower (60 sec)	Mainland Approx 350 MW[13]	Tasmania Approx 60 MW[13]	A$ 4.5 million (NEM 2004-5)	When the local frequency changes above or below the tighter limit of the normal operating frequency band	Yes; a Market Load registered as a market ancillary service.
Non-spinning reserves (non-synchronized)	**Contingency Frequency Control AS** 5. Delayed Raise (5 min) 6. Delayed Lower (5 min)	Mainland Approx 400 MW.	Tasmania Approx 60 MW.	A$ 10 million (NEM 2004-5)	When the local frequency rises or falls through an initiating frequency setting	Yes; a Market Load registered as a market ancillary service.
Voltage Control	**Reactive power ancillary service** Network loading control ancillary service	Mainland: 1300 MVAR leading p.f. 2190 MVAR lagging p.f. Tasmania: Nil leading p.f. 270 MVAR lagging p.f.		A$ 69 million (NEM 2004-5)	Following a credible contingency event. Following a contingency event in a transmission network.	No Yes; given technical requirements met[9]
Black Start	**System Restart**	Up to sixteen system restart sources for the mainland and three for Tasmania.		A$ 10 million (NEM 2004-5)	By instruction from the System Operator	No

Table A-1: Characteristics of the NEM's Markets [NEMMCO, 2005c and 2005b]

[8] These requirements are dynamic and may potentially change at five-minute intervals.
[9] The contracted plant must be capable of disconnecting or reducing its electrical load within five seconds of notification of a network loading condition for a minimum of 15 minutes, and interval metering equipment capable of measuring the load reduction must be provided

A.3 Ancillary Services Arrangements in the NEM

NEMMCO is responsible for the security and reliability of the electricity grid. To fulfill this obligation, NEMMCO controls key technical characteristics of the system, notably frequency and voltage. Reserves relating to frequency control are procured through centralized markets operated by NEMMCO. Reserves relating to network control ancillary services (voltage control and network loading control) and system restart resources are procured through a tender process, resulting in bilateral contracts between NEMMCO and successful tenderers. Typical sources of ancillary services include automatic generation control, governor control, load shedding, and rapid loading or unloading of generating units.

Ancillary services costs were a thorny market design issue from inception of the NEM.[10] During the first three years of operation, ancillary services costs accounted for almost ten percent of total market turnover [NECA 2003]. These high costs, ostensibly due to centralized bulk procurement by NEMMCO, led to introduction of a system of competitive procurement for the most frequently needed ancillary services beginning in 2001.

The present Rules organize ancillary services into three "bundles" – Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), and System Restart Ancillary Services (SRAS). Since 2001 NEMMCO has operated markets for the delivery of frequency control ancillary services (FCAS, sometimes called market ancillary services) while continuing to purchase network control ancillary services (NCAS) and System Restart Ancillary Services (SRAS) under long-term bulk procurement agreements. Ancillary service costs as a percent of total market costs decreased from 6% to under1% between 2001 and 2003, due to use of competitive procurement processes for FCAS (see Figure A-5). The annual cost of the market ancillary service arrangements has dropped from around A$110 million in its first full year of operation to just A$27 million in 2003-04 [Outhred 2004].

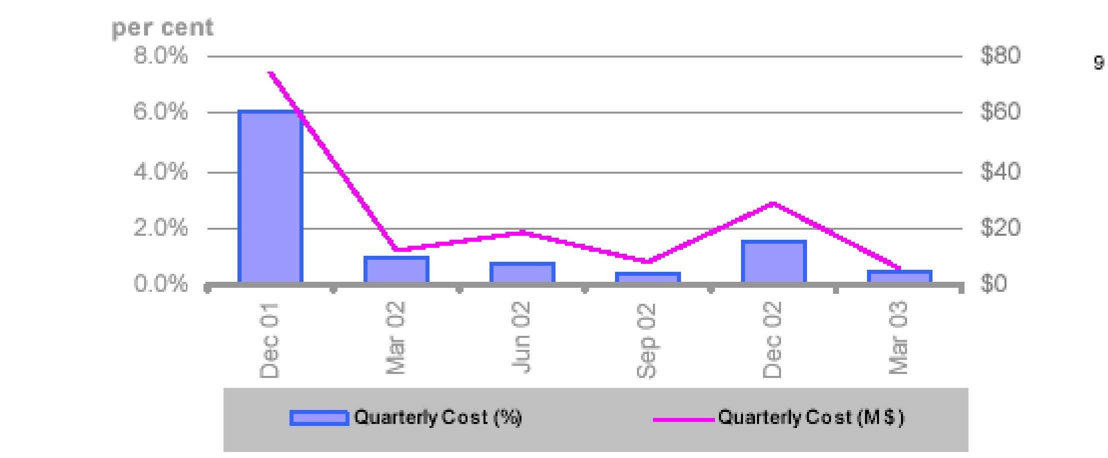

Figure A-5: FCAS Costs (A $millions) & Share of Market Volume, 2001-2003

[10] This is not uncommon in the power sector reform process, as ancillary services lie at the interface between engineering and commercial management of electricity industry transformation.

Although Market Generators and Market Loads bid their output or loads into the FCAS on a daily basis, most of the FCAS market turnover is event driven. More than a third of the total market turnover in 2003-2004 occurred in just three events requiring local services, the most significant of which was a March 2004 reliability incident (see Table A-7), when the Victoria - South Australia inter-connector tripped. Frequency control services were required to be sourced locally with prices at or close to the VoLL level of $10,000. The total price for those services on that day alone was A$5.3 million, about one-quarter of total annual turnover [NECA 2004a].

FCAS are the most frequently used and therefore the most costly, accounting for almost three-fifths of total ancillary services turnover (See Table A-2). Under the "causer-pays" system of settlement, NEMMCO determines and allocates ancillary services costs to the responsible market participant (e.g., Market Customers or Market Generators).[11] With the reduction in overall FCAS costs, NCAS costs have become a proportionally greater share of total ancillary services cost.

Ancillary Service Type	**Settlement Cost ($M)**		**Customer Recovery ($M)**	**Generator Recovery ($M)**
Frequency Control	$138.4	58%		
Contingency FCAS	*$119.5*	*50%*	*Lower services $36.3*	*Raise services $83.2*
Regulation FCAS	*$19.9*	*8%*	*$14.9*	*$5.0*
Network Control	$79.8	34%	$79.8	
System Restart	$18.3	8%	$9.1	$9.1
TOTAL	$237.4	100%	$140.1	$97.3

Table A-2: Ancillary Services Market Volume (Sept 2001-April 2003)

Frequency Control Ancillary Services (FCAS) are used to balance power supply and demand over intervals too short for the energy market to manage (e.g., less than five minutes). There are several different frequency control ancillary services, including two types of regulation services and six types of contingency services (see Table A-3). *Regulation Raise and Lower Services* correct the supply and demand balance in response to minor deviations in demand or generation. These services are required dynamically and their delivery is centrally controlled by NEMMCO. Regulation frequency control services are provided by generators equipped with Automatic Generation Control. This allows NEMMCO to continually monitor system frequency and control generating units to ensure that frequency is maintained between 49.9 and 50.1 Hertz. Loads generally do not provide regulation frequency control. *Contingency frequency control services* are required for correcting the supply-demand balance following a major imbalance event, such as the failure of a generating unit or transmission line (NEMMCO 2006a). Some forms of demand side participation – notably load shedding – can and do participate in providing contingency frequency control services.

[11] Under the "causer pays" philosophy individual contribution to the aggregate deviation in frequency of the power system is assessed, and each Market Generator is required to participate in the causer pays regime. Those Market Generators are each allocated a 'causer pays' factor by NEMMCO on a monthly basis that represents the extent to which the generating unit(s) caused frequency deviations over the previous month. Generators contribute to the cost of regulation frequency control ancillary service in accordance with their causer pays factor. Historically, Market Generators pay about 30% of regulating service costs, and Market Customers pay the remainder.

There are strict rules governing participation for any resource providing FCAS, especially for the quick-response categories (e.g., Fast Raise and Fast Lower Service):

- The ancillary services generating unit or load must have a control system (either a proportional controller or switching controller) that automatically initiates a fast raise or fast lower response depending on which is called for by system frequency conditions;
- The ancillary services provider must inform NEMMCO of the details of the control system, in order to facilitate central dispatch or determining frequency settings;
- The ancillary services provider must install measurement equipment, at or near the connection point, allowing under-frequency load shedding (relaying) to occur at intervals of 50 millisecond or less;[12]

Frequency Control Service	Purpose	Description	Typically provided by:
Regulation Raise and Lower Services	Regulation Deviation	Generation or load response to remote signals for frequency control	Automatic generator control
Contingency Services - o Fast Raise and Lower Service (6 sec response) o Slow Raise and Lower Service (60 sec response) o Delayed Raise and Lower Service (5 min response)	Large deviation contingency	o Rapid generation or load response to low frequency o Generation or load response to low frequency o Generation or load response to low frequency deviation beyond a threshold	Governor, load shedding, or rapid generator loading/unloading

Table A-3: FCAS Services and Providers [NEMMCO, 2005b]

Network Control Ancillary Services (NCAS) allow the operator to maintain and extend the operational efficiency and capability of the network within secure operating limits. There are two types of NCAS – voltage control (usually through generators with automatic voltage regulators (AVC) and synchronous condensers) and network loading control. Network loading control is required only in Victoria. NCAS are procured centrally on a biennial basis, but providers update their availability weekly. Load customers that meet the stringent response performance and telemetry requirements are eligible for this service, and loads now provide 100% of the network load control requirement.

System Restart Ancillary Service (SRAS) allow the operator to recover from black-outs by restarting service on an island basis and then slowly synchronizing other portions of the network until network operations are fully restored**.** Only generators are capable of providing this service.

A.4 Load Provision of Ancillary Services

[12] If agreed with NEMMCO, where a switching controller is used the measurement of power flow representing the generation amount or load amount may be made at intervals of up to 4 seconds

The design of the NEM provides multiple entry points for demand-side resources to participate in providing ancillary services and network support. In this section we provide an overview of these demand-side entry points, including quantitative information on market share where available. We conclude by summarizing regional variations in demand-side participation.

Despite these multiple entry points there has been concern expressed by regulators and others regarding low levels of demand side participation. A 2002 report by the New South Wales electricity regulator concluded that levels of demand response were far below what was necessary for a well-functioning market [IPART 2002]. The report noted that customers with peak demands coincident with high spot prices in the NEM (e.g., residential consumers) faced no price signals regarding their use of electricity during these critical periods [Council of Australian Governments 2002].[13] These and other studies have led to recent mandates at the State level in Australia to install universal interval metering.[14]

A.4.1 Overview: Entry Points for Demand Side Participation

There are at least eight entry points for Market Participants to mobilize demand-side resources at both the retail and wholesale level to participate in the NEM:

- Market Customers, usually retailers, can contract blocks of load which can be curtailed for either economic reasons (e.g., as a hedge against high prices faced by retail suppliers in the spot market) or in response to reliability or contingency events;
- As a direct Market Participant, Market Loads and Market End-Use Customers can adjust their demand according to half-hourly spot prices;
- Market Participants can respond to NEMMCO tenders for load to be contracted for as reserves when there is forecast to be a reserve margin shortfall (relative to levels established in the Reliability Rules);
- In Victoria only, Market Participants can respond to NEMMCO tenders for load to be contracted for Network Load Control purposes;
- Network Service Providers (NSPs) can field energy efficiency or demand response programs to support the deferral of capital expenditure for load growth-related network expansion or reinforcement;
- Market Customers can contract blocks of load and bid them in as Scheduled Loads in either the Energy or the Frequency Control Ancillary Services markets;
- Market Customers can be configured with frequency-activated load shedding devices as a compulsory condition of service; and
- Retailers can be required by Network Service Providers to shed load blocks and retail customers in response to large-scale reliability or contingency events.[15]

[13] The report concluded that it is actually more important that end-users are exposed to the NEM prices than whether end-users respond to price.
[14] Victoria's Essential Services Commission mandated deployment of universal interval meters beginning in 2006.
[15] End-users either pay the price cap or they are interrupted and the price cap is set sufficiently high that they should really be indifferent as to whether they are interrupted or left to respond voluntarily to the high spot price.

A.4.2 Demand Side Participation in the NEM's Energy Markets

Demand response has not yet made significant inroads into the NEM's physical or financial markets. At present the largest volume of demand side participation is via retail contracts. In this arrangement electricity retailers have contracts with end-users that include provisions for load curtailment, with some sharing of the benefits that accrue to the retailer when curtailment is exercised. However, the extent of this demand participation is hard to quantify, as it is tied up in commercial contracts which are not required to be disclosed to NEMMCO or regulators. NEMMCO estimates the amount of demand response available through retailer contracts at 300 MW (see Table A-4), most of it located in Victoria and Queensland [NEMMCO 2005a].[16]

	2004 SOO (MW)	**2005 SOO (MW)**
Queensland	157	100
New South Wales	14	10
Victoria/South Australia	163	191
Tasmania	0	0
TOTAL	334	301

Table A-4: Demand Response Participation in the NEM's Electricity Markets [NEMMCO, 2005a]

Since retailers are primarily price-takers, they have strong incentives to hedge themselves in the market place.[17] Retailers will enter into hedging contracts with generators to build peaking plant and will also contract with loads for curtailment or price responsiveness. The details of these arrangements are largely confidential. Depending on contractual specifics including savings sharing arrangements, retailers typically own-purchase or invoke their power or load curtailment contracts when prices exceed $300/MWh. Since frequency deviations and reserve needs are invariably accompanied by price excursions up to and including the VOLL cap, these retailer-invoked, price-induced load curtailments also contribute to maintaining network stability.

NECA's December 2000 survey of demand-side participation in the NEM indicated 817 MW of demand side response was available from programs offered by the retailers, Transmission Network Service Providers (TNSPs), Distribution Network Service Providers (DNSPs) and Generators that had responded to the survey. In aggregate, these respondents represented a customer base of 2,154 MW in peak demand. However, 800 MW of the demand response identified was contributed by only one customer. Removing this single major customer would reduce the remaining load reduction to just 1.3% of the surveyed maximum demand (NECA 2001).

[16] The source of this information is a survey conducted by NEMMCO in conjunction with the relevant state-wide Transmission Network Service Providers and local Distribution Network Service Providers. This approach likely understates DR participation, nor does it reflect the substantial amounts of interruptible industrial load, which may total 2000 MW.

[17] Average spot prices are in the range $30 to $50 per MWh, but can spike as high as $10,000/MWh during system disruptions or extraordinary peaks.

A.4.3 Market Load (End-User) Participation in the NEM

Through being a direct Market Participant in the NEM (a Market Load, or Market End-Use Customer) an individual end-user can adjust their demand upwards according to the half-hourly spot price. The technical requirements to be a Market Participant are quite considerable, however, and as a result only four large end-users are currently participating in the NEM in this fashion.[18] As with retailers curtailing retail customers during high price periods, Market Participants reducing their consumption in response to high prices will contribute to maintaining network stability. These customers are also exposed to the VOLL during contingency events.[19]

A.4.4 Mobilizing Demand Response in Response to Reserves Tenders

According to Electricity Users Association of Australia (EUAA), the main reason for the relatively low uptake of demand response in the NEM is due to a lack of proper incentives to either end users or retailers or network service providers. EUAA also states that a second barrier has been simply a lack of awareness of business opportunities accruing to NEM market participants bidding load into various markets [EUAA 2005]. EUAA has actively worked with their membership to help boost demand side participation, most recently in response to NEMMCO's 2006 *Invitation to Tender for Reserves*.[20] On September 23 2005, NEMMCO issued an invitation to tender for 500 MW of additional reserves to be made available over the period 16 January 2006 - 10 March 2006.[21] Several demand-based bids were submitted (see Box 1).

A.4.5 Demand Response Providing Network Load Control Ancillary Services

As mentioned, NEMMCO contracts annually for provision of network load control, part of the bundle of non-market ancillary services. Network load control is only required in Victoria. In 2005 all of the 350 MW of network load control required was contracted for bilaterally by NEMMCO at a monthly cost of about $35,000.

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[18] They are: Sun Metals Corporation, Tomago Aluminum Company, and Yamasa Australia. See: NEMMCO Market Participant registration list (http://www.nemmco.com.au/registration/044.htm)

[19] The Electricity Rules distinguish between Credible and Non-credible Contingency Events. A credible contingency is an event that the system operator considers has a likelihood sufficiently large that the system should be operated to withstand it. A Non-credible Contingency has a likelihood of occurring so small that the system operator determines it is not worth incurring the additional costs of operating the system to withstand it. Examples of non-credible contingencies include the failure of multiple generating units or the collapse of a transmission tower.

[20] This tendering process was called into play as part of the reliability safety net process, as forecast reserves in Victoria and South Australia in Winter 2005/2006 are forecast to be below the 50% POE level.

[21] Under Clause 3.12.1 of the Reliability Rules adopted by the Reliability Panel of the AEMC, NEMMCO must publicly call for competitive tenders for the provision of reserve, if any region is forecast to have a reserve shortfall within a 2-6 month period. In doing so NEMMCO must seek the views of the participating network service provider on the value of contracting for reserve, and not enter into a contract for reserve unless NEMMCO is satisfied that the benefits of entering into a contract are likely to exceed the costs, on the basis of reasonable assumptions about key parameters, including expected demand.

Energy Response Pty Limited (ERPL) is a commercial firm specializing in aggregating demand side resources (DSR) for response to reserve or other tenders from NEMMCO or individual DNSPs. ERPL has contracted and registered more than 300 MW of DSR in its first full year of operation, and recently achieved successful dispatch of aggregated DSR for 3 major electricity retailers in the past few months.

Any DSR registered by ERPL is pre-tested to ensure curtailment quantity, reliability, time availability, temperature sensitivity, sustainability, and communications connectivity. Only after these tests are completed can the contract be concluded and the aggregated load offered to a DNSP or NEMMCO.

The scheme used by EPRL to compensate contracted loads has two components:
1. Availability ($/MWh) for being available through specific hours in case they are called;
2. Dispatch ($/MWh) for providing the contracted DSR when called to do so.

Failure to deliver when dispatched results in a pro-rata forfeit of the last period (generally a month) of the availability payment; this compensation remains lower until the original curtailment amount is demonstrated by a re-test.

A key issue in aggregating loads for commercial purposes is the education of the DSR provider. ERPL spends considerable up-front effort informing the DSR providers of their obligations, the importance of their reliable performance, and the financial and other rewards from participating.

Box 1: Commercial Load Aggregation Business Model [Energy Response 2005]

The result of the reliability safety net tendering process was announced in January 2006. NEMMCO procured a total of 375 MW of reserve capacity (See Table A-5), with conditions ranging from 1 hour per day to 15 hours per day and limits on the total hours of usage, all of which were taken into account in the evaluation process. The cost of this reserve includes availability, pre-activation and usage components, and thus the total costs will be driven by the amount of pre-activation and use. NEMMCO estimated that total costs will range between A$4.4M to A$4.9M over the two month period.[22]

Successful Tenderers	Contracted Reserve
State Electricity Commission of Victoria trading as VicPower Trading	180 MW
Energy Response Pty Ltd	125 MW
The Australian Steel Company (Operations) Pty	55 MW
Zinifex Port Pirie Pty Limited	15 MW

Table A-5: Successful Tenders under NEMMCO's 2006 Reliability Safety Net Tender

A.4.6 Aggregating Demand Response (or Energy Efficiency) to Reduce Network Expansion Requirements

Demand side participation for purposes of managing network expansion needs, sometimes called demand management, is a major entry point for demand side participation in Australia, especially in New South Wales. The largest project is the Sydney Demand Management and Planning Project (DMPP), budgeted at $10 million over five years and focused on identifying the potential for reducing the demand for electricity by all classes of consumers in the inner

[22]Costs for the reserves will be shared between the affected jurisdictions (Victoria and South Australia), allocated based on their relative energy demands. These costs are then passed on to market customers according to their relative energy consumption during business hours.

Sydney region [Transgrid, 2005]. A similar project is a survey of all standby generators in NSW focused on creating a database on standby generation useful in reducing the net peak demand that would have to be satisfied by DNSPs during periods of high demand or low reserves [Next Energy, 2005]. Depending on how the demand is configured (e.g., dispatchability) there could be potential ancillary or network services value to this demand side participation as well.

A.4.7 Loads Scheduled for Participation in FCAS or other Markets

NEMMCO data for 2004 indicate only four Market Participants with scheduled loads in the NEM. These consist of several pumping stations totaling 1320 MW (See Table A-6) and a single large industrial customer with 660 MW of metal melting load. The Code sets out requirements for telemetry (SCADA), metering (50 msec resolution interval metering) and settlement, which are equivalent for both loads and generators. It is not clear how many weekly FCAS tenders are submitted by these Market Participants, nor how much of the A$23.5 million in FCAS annual turnover flows to Market Participants vs. Generators.

Participant	Station Name	Region	Dispatch Type	Class	Type	Phy. Unit No.	Unit Size (MW)	AGG	DUD	REG CAP (MW)
Eraring Energy	Bendeela No. 1 Pump	NSW	Load Norm Off	MS	Hydro	1	40	Y	SHPUMP	240
	Bendeela No. 2 Pump	NSW	Load Norm Off	MS		2	40	Y		
	Kangaroo Valley No. 3 Pump	NSW	Load Norm Off	MS		3	80	Y		
	Kangaroo Valley No. 4 Pump	NSW	Load Norm Off	MS		4	80	Y		
Snowy Hydro Limited	Snowy	Snowy	Load Norm Off	MS	Hydro	1	600	N	SNOWYP	600
Tarong Energy	Wivenhoe Power Station No. 1 Pump	QLD	Load Norm Off	MS	Hydro	1	240	N	PUMP1	240
	Wivenhoe Power Station No. 2 Pump	QLD	Load Norm Off	MS	Hydro	2	240	N	PUMP2	240
MS = Market Scheduled										

Table A-6: Scheduled FCAS Loads from Market Participants (January 2005)

A.4.8 Mandatory Load Shedding During Reliability Events

The value of emergency load shedding during system disturbances and weather-driven load excursions has been demonstrated repeatedly within the NEM context. There were four reliability or multiple contingency events during the period 2004-2005 when mandatory load shedding or contracted (voluntary) load curtailment was called upon (See Table A-7). During several of these events the spot price approached the VoLL limit of $10,000 in the regions affected. In each of these cases the availability of frequency-activated and manually-activated demand response, whether contracted or compulsory, helped prevent voltage collapse and restore stability.

The Electricity Rules provide for automatic interruption of Market Customers (typically large industrial loads such as smelters and arc furnaces) during severe under-frequency events. These customers are obligated to install frequency-activated load shedding devices which are set to trip when frequency falls below operator-determined set points, usually between 49 and 49.5 Hz. Such low frequency excursions result from both credible and non-credible contingency events.[23] Participation in this category of demand response is substantial, up to 50% of the market demand in some networks, albeit involuntary.[24]

Date of Contingency Event	Nature of Contingency	Areas Affected	Demand Response	Percent of Market Demand	Frequency drop	VOLL Flagged?
14 March 2005	275 kV fault caused Vic-SA separation	South Australia	700 MW automatic load shedding	50 %	47.76 Hz	Yes
1 Dec 2004	Low reserves due to high demand	NSW	500 MW manual load shedding	4.0 %		No
13 August 2004	Current Transformer explosion in NSW	NEM-wide	1,550 MW automatic load shedding	7 %	48.9 Hz	No
8 March 2004	Ground fault causes system separation	Victoria and SA	650 MW		47.6 Hz	Yes

Table A-7: Demand Response During NEM Reliability Events (2004/2005)

Under frequency load shedding proved its worth during the August 13 2004 CT (currency transformer) explosion in the Bayswater 330 V switchyard. The subsequent buss fault caused no fewer than six generators to trip, removing 3100 MW of load (14% of total NEM). Frequency dropped to below 49 Hz, causing automatic industrial load shedding of over 1500 MW. Analysis of this severe contingency event concluded that under-frequency load shedding successfully averted a serious widespread blackout [NEMMCO 2004c].

Some industrial customers have complained about the lack of compensation for these involuntary interruptions:

> "All frequency loads in NSW may be interrupted in response to a significant frequency or voltage disturbance. NEMMCO controls the manner and order in which such load shedding is undertaken…When under-frequency load shedding occurs, neither NEMMCO nor any market participants are obliged to compensate the affected loads for any economic loss or to account for any profits made. In effect the (industrial) load provides free insurance to the NEM to cover exceptional events. Providers of FCAS to the NEM will receive a

[23] A credible event is included in the contingencies considered in planning the power system. A non-credible event is a contingency considered so unlikely that including it in system planning would exceed probabilistic reliability requirements and result in a system that is too costly relative to the value of unserved energy

[24] The interruption is involuntary. Interrupted end-users are indirectly compensated because they are not charged the price cap for energy that has been interrupted, whereas all other end-users are. However, the situation is more complicated for end-users served by retailers, who are less able to directly pass on the high spot prices.

> windfall gain as both energy and FCAS prices invariably spike towards VoLL on the occurrence of market events leading to load shedding. At the same time, large industrial loads face economic loss from being shed and receive no compensation for the service they offer to the NEM…" [NECA 2004a].

Table A-8 compares the under-frequency regimes corresponding to compensated ancillary services provision and compulsory under-frequency load shedding.[25] The AEMC has recognized that the distinction between credible events (covered by the Reliability Rules and planned and provided for by NEMMCO via its ancillary services arrangements) vs. non-credible events (not planned for and not provided for but rather handled with compulsory emergency arrangements) begins to pale when there "is a significant amount of unserved energy due to multiple contingency events".

Action	**Frequency**
Contingency FCAS - Lower	> 50.15 Hz
Regulation FCAS - Lower	50.0 - 50.15 Hz
Optimal Operation	50.0 Hz
Regulation FCAS - Raise	49.85 - 50.0 Hz
Contingency FCAS - Raise	< 49.85 Hz
Underfrequency trip	49.0 Hz
Note that underfrequency tripping is not a contracted Ancillary Service.	

Table A-8: Frequency Regimes for Operation of FCAS vs. Mandatory Load Shedding

A.5 Variation in Demand-side Participation by State

Table A-9 summarizes the demand side participation within the major NEM markets as reported by NEMMCO [NEMMCO 2005c]. The extent to which these demand-side entry points have proven successful varies considerably by state. These variations in the extent and type of demand side participation reflect patterns of capacity sufficiency, capital expenditure priorities, level of engagement by retailers and network service providers, and state-level regulatory support.

Both South Australia and Victoria share a need for effective demand response given their relatively weak interconnection to the rest of the NEM and the considerable temperature-sensitivity of the regional system demand. The Essential Services Commission of South Australian (ESCOSA) has allocated A$20 million to the principal DNSP to trial several demand management and demand response initiatives. Targeted areas will likely include standby generation, curtailable loads, critical peak pricing, residential direct load control, and demand aggregation [ETSA Utilities 2005]. Victoria was quite active early on in encouraging demand response as part of electricity restructuring, including conducting a demand response auction which netted 200 MW of capacity bids. As Victoria is the only state where electricity ownership is fully privatized, retail competition and market development has penetrated

[25] The rebuttal to this customer's view is that the retail tariffs they pay are lower than they otherwise would be due to these interruptibility provisions, which reduce the likelihood that the loads will be connected when NEMMCO sets the NEM spot price to the price cap.

further. This may well explain the high level of reported retail demand response reported by VENCorp and other Victorian DNSPs [Sustainable Energy Authority Victoria 2004].

New South Wales (NSW) has had less of an imperative to undertake demand response, as they are the most strongly interconnected part of the NEM and have a comfortable capacity reserve. However, the NSW electricity regulator has been supportive over the years, including enacting the so-called “D Factor”, which allows Distribution Network Service Providers (DNSPs) to retain capital expenditures avoided through targeting of demand management. Additionally, the NSW energy agency has recently commenced a large Demand Response/Energy Efficiency initiative (the Energy Savings Fund) which will provide some A$ 200 million to individual energy-saving and peak-reducing projects over five years [Dept. of Energy, Utilities and Sustainability 2005]. There is also evidence that some early investment decisions are now being taken with respect to peaking generation and transmission & distribution augmentation needed in the 2008/2009 timeframe; there may be an opportunity for effective demand response now to defer such investment decisions [Outhred 2005]. However, given high capacity margins and the weak extent of retail competition, the most likely venues of demand response in NSW in the near term will be driven by DNSPs facing network constraints and capital expenditure approval requirements.[26]

Queensland is also blessed with adequate reserves until 2008/2009. Retail competition remains sparse, and the main problems faced by DNSPs are high rural/urban/suburban cost of service differentials, maintenance of the extensive and lightly-loaded network, and overloaded substations in some fast-growing urban and suburban pockets.

Tasmania only joined the NEM in 2005 and will soon be interconnected to the National Grid via a submarine cable.[27] Since joining the NEM, average electricity prices have been more than double those of the mainland regions, due to a multi-year drought and overdependence on hydropower.[28] Once Basslink is in service there will be strong opportunities for demand response whenever the interconnection trips or is overloaded.

Western Australia is not part of the NEM, nor will it be any time in the foreseeable future. In 2004 the single DNSP serving Western Australia, Western Power, faced capacity shortages that resulted in load shedding.[29] As a result a large-scale demand response program was developed – the Peak Demand Saver Program – comprising large industrial customers capable of providing load curtailments of pre-specified frequency and duration on notification by the

[26] The NSW DM Code of Practice requires DNSPs to exhaust demand management as an alternative before undertaking load-driven network expansion or reinforcements

[27] The Basslink interconnector will run from Loy Yang in Gippsland, Victoria, across Bass Strait to Bell Bay in northern Tasmania. When installed the 290 km undersea cable component will be the longest of its type in the world. Basslink will have the capacity to export up to a maximum of 600 megawatts of power from Tasmania to Victoria, and import a maximum of 300 megawatts to Tasmania. National Grid of the UK is the owner and operator of Basslink. Basslink is now in the commissioning phase.

[28] It can be argued that the high prices are due to insufficient competition in generation in Tasmania, where there is effectively only one state-owned generation company. Thus Hydro Tasmania has the ability to set price in the Tasmanian region of the NEM.

[29] The exact cause of the shortage was a lack of contracted gas to meet unexpectedly high demand rather than a shortage of generating capacity.

system operator. Customers were paid both an availability (reservation) payment and a dispatch payment when called upon [Charles River Associates, 2005].

Comparable North American Electricity Market	Australian Markets and Service Requirements	No of participants by sector (residential, commercial, industrial)	Total enrolled load in MW by sector (residential, commercial, industrial)	Actual average load curtailments delivered (by sector)
Energy	**Energy** 1. Spot trading	3 comm'l	1320 MW	N/A
Regulation	**Regulation Frequency Control AS** 1. Regulating Raise (see cells) 2. Regulating Lower (see cells) **Uncompensated Load Shedding**	None 60% of customer load		
Spinning Reserves (synchronized)	**Contingency Frequency Control AS** 1. Fast Raise (≤6 sec) 2. Fast Lower (≤6 sec) 3. Slow Raise (60 sec) 4. Slow Lower (60 sec) 5. Delayed Raise (5 min) 6. Delayed Lower (5 min)	3 comm'l[30] 1 industrial[31]	1380 MW 660 MW	N/A N/A
Non-spinning reserves				
Network Control	Network Loading Control[32]		350 MW	

Table A-9: Demand Side Participation in the NEM Markets [NEMMCO 2005c]

[30] Water pumping loads
[31] Aluminum smelter load
[32] Network loading control is required only in Victoria.

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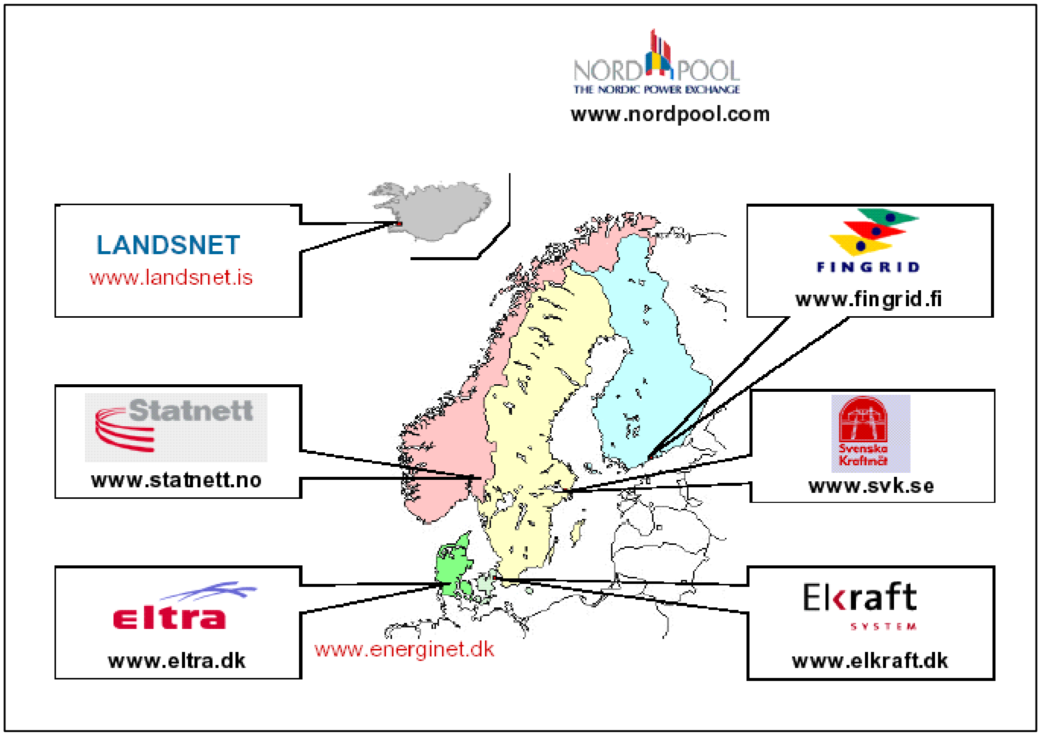
B. Nordic Electricity Market: Ancillary Services and Load Participation



B.1 The Nordic Electricity Market: Overview

The four economies comprising the Nordic region (Denmark, Finland, Norway and Sweden) were among the very first to restructure their electricity industries and introduce competitive wholesale electricity markets. Nord Pool, established in 1993, was the world's first multinational power exchange. Nord Pool operates several regional financial and physical markets (see Figure B-1), most notably the forward market (Eltermin and Eloptions), the day-ahead market (Elspot), and the real-time or hourly market (Elbas, or Electricity Balancing Adjustment Service).

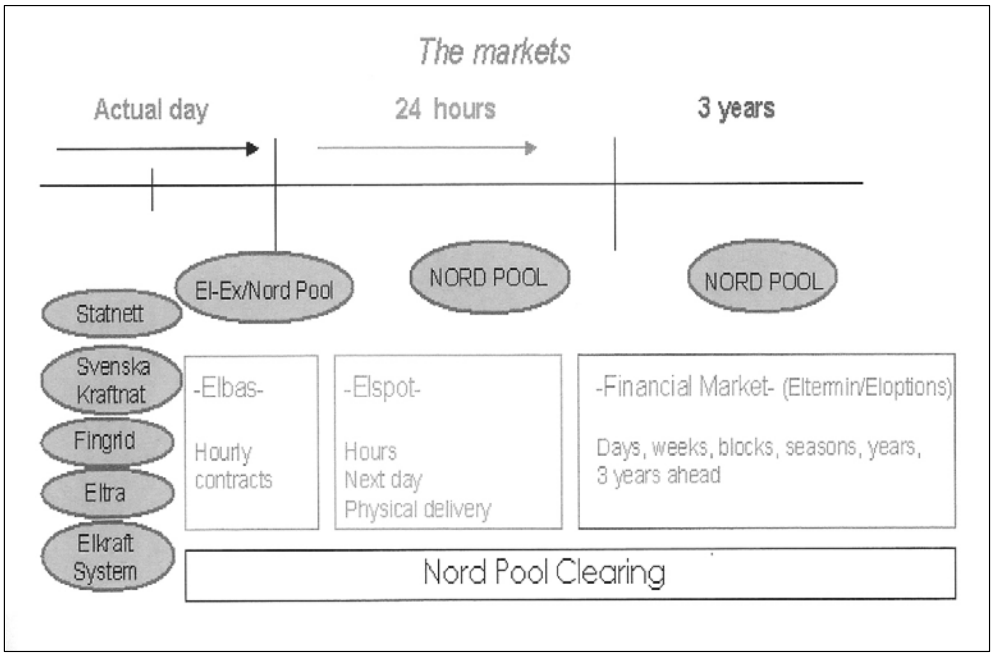


Figure B-1: Physical and Financial Markets Operated by Nord Pool

Elbas is the intraday (hourly) market, currently serving only Finland, Eastern Denmark, and Sweden. The Elbas market supplements Elspot and the national Nordic regulating power markets.

Nord Pool is an energy-only market but is supported by limited operating reserves financed by the national grid operators via capacity payments. There is significant price volatility under this market design, as high spot prices signal consumers to reduce their electricity demand (or use back-up sources) and power companies to invest in generation capacity and/or demand flexibility. Traded volumes through Nord Pool in 2004 amounted to 111.2 TWh in Elspot (including 0.9 TWh in Elbas), 910 TWh in financial trade, and 1,748 TWh in bilateral contracts.

A power system cannot operate without operating reserves, otherwise any positive deviation from the demand forecast or outage would cause a loss of load. In the Nordic model two types of reserves are used: (i) primary reserves, calculated based on dimensioning outages characteristics of the system; and (ii) secondary reserves, which serve both to relieve primary reserves after outages and also to cope with deviations from forecasts. Anytime there is a tight balance between demand and supply, the generators will have an incentive to bid their capacity into the day-ahead spot market instead of the hour-ahead Elbas or real-time regulating power market. The result would be a spot market that clears but insufficient generation reserves bidding into the Elbas or regulating power market, thus jeopardizing real-time system balance. The Nordic solution is to contract certain quantities of operating reserves to be available only in the regulating power market. Because the conditions placed on these secondary reserves are more "DR-friendly" (e.g., non-synchronized, 15 minute activation time), it is not surprising to find a very high level of demand response participation in the Nordic operating reserves scheme.

B.1.1 The Regional System and the National Grid Operators

The population of the common Nordic electricity trade area is 24 million, with 5.4 million in Denmark, 5.2 million in Finland, 4.5 million in Norway and 8.9 million in Sweden. National and regional electricity statistics (2001) are shown in Table B-1.

KEY FIGURES FOR THE NORDIC ELECTRICITY SYSTEM FOR 2001

		Denmark	Finland	Iceland	Norway	Sweden	**Nordel**
Installed capacity	MW	12 480	16 827	1 427	27 893	31 721	**90 348**
Generation	GWh	36 009	71 645	8 028	121 872	157 803	**395 357**
Imports	GWh	8 603	12 790	.	10 753	11 167	**43 313**
Exports	GWh	9 180	2 831	.	7 161	18 458	**37 630**
Total consumption	GWh	35 432	81 604	8 028	125 464	150 512	**401 040**
Breakdown of electricity generation:							
Hydropower	%	0	19	82	99	50	**55**
Nuclear power	%	.	31	.	.	44	**23**
Other thermal power	%	88	52	0	1	6	**20**
Other renewable power	%	12	0	18	0	0	**2**

. No nuclear power production

0 Less than 0.5 %

Table B-1: Nordic Electricity System Statistics (2001)

As part of the Nordic restructuring process, parliaments in each country passed legislation establishing national transmission system operators. There are five Nordic Transmission System Operators (TSOs): Eltra and Elkraft (Western and Eastern Denmark, respectively)[33], Fingrid (Finland), Statnett (Norway), and Svenska Kraftnat (Sweden). Each TSO is responsible for ensuring equal treatment and open access for all market participants, facilitating physical delivery of electricity purchased under bilateral contracts or from the power exchange, ensuring system adequacy and system reliability according to common reliability standards, managing transmission constraints and operational disturbances, maintaining system protection, and managing market imbalances.

.

The installed capacity in the four countries is about 90 GW with a concurrent system peak of about 70 GW of the interconnected system (see Table B-1). Various transmission

[33] Elkraft and Eltra became part of Energinet.dk as of October 1, 2005. Energinet.dk was established under Act No. 1384, Act on Energinet Denmark.

interconnections allow for power exchange between the four national systems as well as with neighboring non-Nordel TSOs, including UCTE (Union for the Coordination of Transmission of Electricity) and Russia (see Figure B-2).

Figure B-2: The Nordic Grid and Neighboring Country Interconnections [Nordel, 2004]

B.1.2 Regional Cooperation through Nordel

Nordel is a voluntary organization that promotes cooperation between the system operators in Denmark, Finland, Iceland, Norway and Sweden and other participants in the Nordic electricity market. Nordel administers the System Operations Agreement (Operations Code) agreed to by the national TSOs, which is binding for market participants in the national and regional markets. It operates via a committee system similar to the North American Electric Reliability Council (NERC), and focuses on:

- system development and rules for network planning and operations;
- system operation and security, reliability of supply, and information exchange;
- market development;
- transmission and ancillary services pricing; and
- maintaining contacts with power sector organizations and regulators throughout Europe.

B.1.3 Resource Adequacy in the Nordic Electricity Market

The Nordic electricity market is heavily dependent on hydropower and thus is vulnerable to drought-induced price volatility. In 2002-2003, a sharp reduction in inflow to hydro reservoirs during late autumn pushed electricity prices to unprecedented levels, severely testing the marketplace (see Figure B-3). Although the market structure ultimately worked (e.g., loads curtailed in response to high prices and high prices stimulated development of new capacity), consumers and the Nordic economy were adversely affected. Among the capacity additions stimulated by these high prices are wind power, gas turbines, and a nuclear power plant scheduled for 2009 completion.

Discussion continues regarding relative responsibility of providers and grid operators for ensuring resource adequacy under abnormal conditions such as high peak demand or energy shortfalls. There has been a tendency to foist the responsibility to handle peak demands, especially during conditions of drought, onto the TSOs.

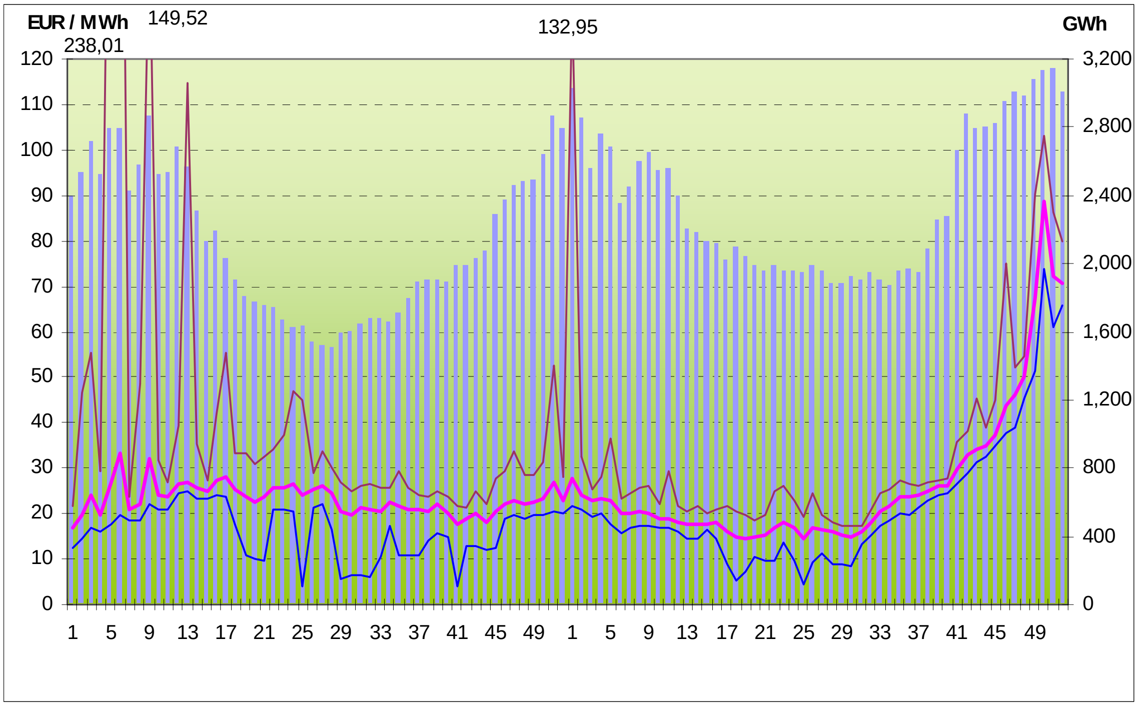


Figure B-3: ELSPOT Prices & Volume CY01-02 [*http://www.nordpoolspot.com/*]

B.2 Regulation and Operating Reserves in the Nordic Electricity Market

B.2.1 Reliability Basis for the Reserve Requirements

The Operating Code promulgated by Nordel specifies how reserves requirements are to be derived from market balancing requirements and reliability rules. Market balancing requirements are calculated using historical statistics and forecasts of hourly imbalances (upward and downward) for each grid area. Reserve requirements stemming from reliability rules include the area-wide N-1 contingency (dimensioning fault) and the bounds of any area imbalance.[34] These calculations determine the requirements for frequency-controlled and manually activated operating reserves, respectively.

B.2.2 Balance Management, Regulating Power and Operating Reserves

In September 2002 a common Nordic balancing market, the Regulating Power Market or RPM, was established. This Balancing Market is a key tool of all Nordic transmission system operators, as it provides the means for real-time balancing of electricity supply and demand due to load forecast errors, system disturbances, or other causes. Although each Nordic TSO operates its own variant of the RPM, the operating reserves of one TSO may be applied to relieve imbalances elsewhere in the Nordic grid. The Balancing Market ensures an efficient acquisition of reserves on an hourly basis, but does not in itself reduce the required amount of reserves. It was introduced as an efficient way of securing sufficient reserves from existing capacity during peak load periods. This helps control the risk associated with balance

[34] The N-1 contingency is a sudden outage of the biggest power plant on the grid or the loss of the largest transmission line or neighboring grid connection

management, especially for the Norwegian and Danish TSOs who are financially responsible for real-time energy balancing.

The basis for balance management of the synchronous system is frequency control. The entire Nordic power system comprises a single market for regulating power. A single merit order list is used, except when bottlenecks require the regulating power market to be divided. For each hour, the regulation price is determined in all Elspot areas as the margin price of activated bids in the joint regulation list (See Figure B-4).

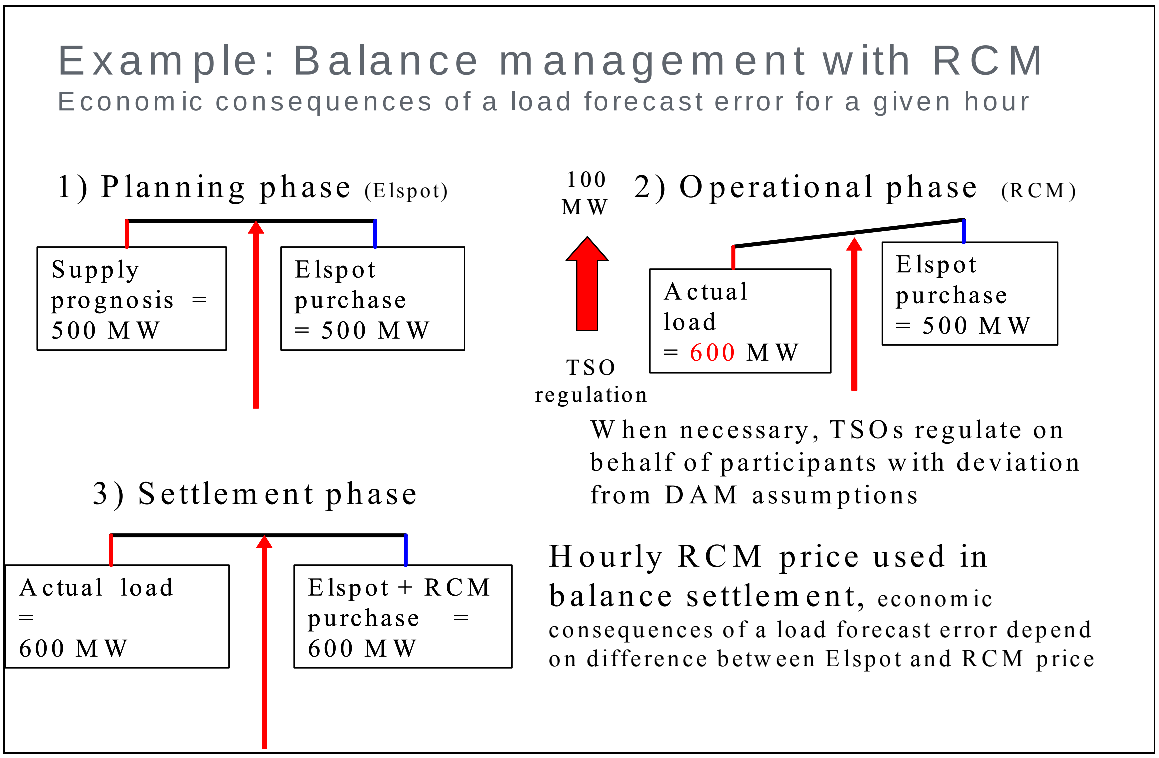


Figure B-4: Balance Management in the Nordic Market

Reserves are categorized by whether they are automatically (via frequency control) or manually activated. Although the TSOs in the Nordic system operate individually in normal balancing operations, there is close cooperation with regard to managing system disturbances. The Nordic TSOs further disaggregate reserves into categories including (see Table B-2):

- Frequency controlled operating reserve (100 % activated between 49.9-50.1 Hz)
- Frequency controlled disturbance reserve (50% activated at 5 sec. and 100% at 30 sec.)
- Fast active reserve (15 min.)
- Slow active reserve (4-8 hours)
- Reactive reserve

The first three categories of reserves operate in tandem, with slower-acting disturbance reserves replacing fast-acting operating reserves as necessary to maintain and restore system stability. Loads can participate in providing disturbance reserves, including frequency controlled disturbance reserve, fast active reserve, and slow active reserve. Loads do not generally provide frequency controlled operating reserve or reactive reserve.

	Regulation and Reserve Service			
Operating Characteristics & Requirements	**Frequency Controlled Operating Reserve**	**Frequency Controlled Disturbance Reserve**	**Fast Active Reserve**	**Slow Active Reserve**
Activation Criteria	Frequency variations within 49.9 and 50.1 Hz	Frequency variations within 49.9 and 49.5 Hz	When needed to replace Disturbance Reserve	When needed to replace Fast Active Reserve
Control & Activation Mode	Primary Control Automatic Activation	Primary Control Automatic Activation	Secondary Control Manual Activation	Secondary Control Manual Activation
Can loads participate?	No	Yes	Yes	Yes
Response Time	100% activated @ ± 0.1 Hz or within 2 minutes	100% activated @ ± 0.5 Hz or 50% within 5 sec and 100% within 30 sec	100% within 15 min	No time requirement
Payments	Hourly and/or Annual payment (per MW or per MW/Hz)	Hourly and/or Annual payment plus (per MW or per MW/Hz)	Hourly and/or Annual payment (per MW or per MWh)	Hourly payment (per MWh)
Monitoring, Metering & Settlement	Real-time monitoring, period testing of regulation capacity	Real-time monitoring, period testing of regulation capacity	Real time monitoring, normal balance settlement	Real time monitoring, normal balance settlement

Table B-2: Operating Requirements of Regulating Reserves in the Nordic Market

The size requirement for frequency-controlled disturbance reserves is determined by the dimensioning fault, which is the largest single contingency in the synchronized system (i.e., N-1 contingency). The requirement for disturbance reserves is 986 MW, distributed by national network as shown in Table B-3. The amount of manually activated Active Reserves is determined by individual network assessments considering the single largest contingency and bottleneck conditions in the transmission system. Table B-3 shows the volume of operating reserves procured by each TSO and for the Nordic region overall. Most of these reserves are procured through market offers or through competitive tenders for specific services, with the TSO and the provider entering into bilateral agreements.

	2003 Peak Demand (MW)	Frequency Controlled Operating Reserve (MW)	Frequency Controlled Disturbance Reserve (MW)	Fast & Slow Active Reserve (MW)
E Denmark	6250	24	90	600
W Denmark			75	620
Finland	13,500	141	205	1000
Norway	20,680	192	313	1600
Sweden	27,300	243	303	1200
Nordel (TOTAL)	**67,800**	**600**	**986**	**5020**

Table B-3: Regulating Reserve National and Regional Volume Requirements

B.2.3 National Arrangements for Regulating Reserves

In Sweden, Svenska Kraftnät (SvK) has separate arrangements for fast and slow reserves, including peaking turbines and load shedding. To strengthen Sweden's wintertime reserve capacity SvK has contracted for 1600 MW of capacity comprising both generation and demand reduction, with the costs allocated across the responsible market players. This arrangement will be in place until 2008, when a market-based solution will take over. SvK also retains 1200 MW of gas turbines suitable for coping with sudden disturbances or for the Balancing Market.

Statnett in Norway relies on its market-based solution, the Regulation Capacity Option Market (RCOM), for provision of operating reserves. Each November Statnett conducts a bidding process and selects the option volumes needed to meet the winter season peak regulation and reserve requirements. Successful bidders (generation or load) are obliged to submit daily offers in the Balance Market. The amount of capacity available has included significant amounts of demand response since a November 2000 pilot bid. Figure B-5 shows the distribution of reserve options volumes between generation and loads during the 2004/2005 winter period. Generally speaking, higher-priced periods resulted in a larger volume and larger share of demand response in the total bids accepted. Demand response has accounted for as much as two-thirds of total volume in some high-cost periods [Stattnet 2005c].

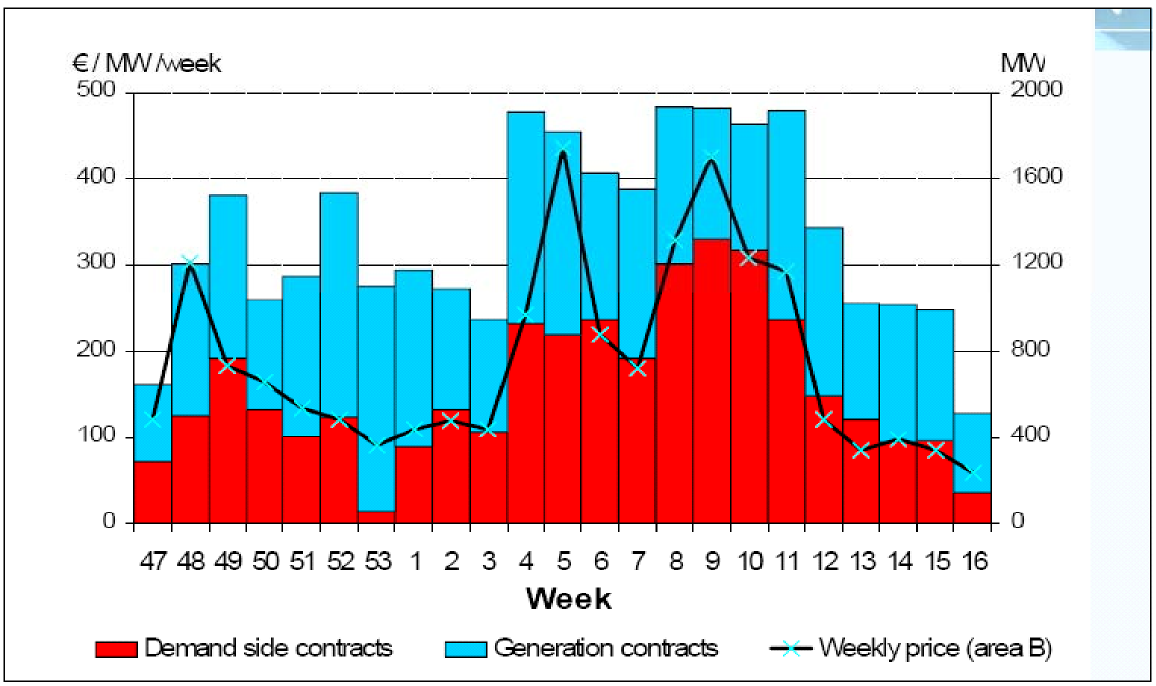


Figure B-5: Regulation Capacity Options Market (RCOM) Volume and Prices, Winter 2004/2005

Fingrid operates a Reserves Bank and a Regulating Power Market. Resource owners can declare their generation and interruptible loads into the Reserve Bank, where compensation and technical and functional conditions are the same for all participants. For Active Reserves, minimum resource size is 15 MW, and resources must be available for 7,000 hrs per year and be able to activate within 15 minutes. Compensation level includes evaluated costs of participation. Total annual budget for fast disturbance reserves is € 10 million, including gas turbines and interruptible loads. Of this amount a small portion goes to imbalance management (10%) and the lion's share to maintaining disturbance and active reserves (90%). Fingrid also contracts for 675 MW of fast active reserves from gas turbines. These resources are also available to the Balance Market to use when market based offers have already been taken.

Elkraft System and Eltra of Denmark have made agreements with the power producers Energi E2 and Elsam, respectively, on the supply of regulation capacity and provision of reserves. Most local purchases of balancing services in Denmark are made through these agreements. Both TSOs have indicated that, on expiration of the present agreements, they will attempt to purchase the services via more competitive mechanism [Sørensen 2005].

B.2.4 Operational Details of Regulating Reserves

The *frequency-controlled operating reserve* is an automatic upward and downward regulation reserve used to maintain grid frequency. Regulation is automatic and commonly implemented by a closed-loop frequency controller at the point of generation (e.g., automatic generator control). The operating reserve is designed to completely activate at 49.9 Hz and 50.1 Hz, respectively. This reserve accommodates any required upwards or downwards regulation within 2-3 minutes. [Nordel 2005a].

These operating reserves are jointly managed by all TSOs in the synchronized Nordic System and are determined once a year based on the previous year's consumption levels.[35] There are stringent telemetry requirements for frequency controlled operating reserves. Each unit must be metered and connected to the IT system of the network operator. The following information must be accessible to the controllers in real time:

- Operational Status
- Active or passive
- Reference frequency
- Dead band for frequency control in [mHz]
- Active regulation band in [mHz]
- Reserved primary regulation (MW)
- Net production or consumption at point of connection (MW)

Frequency-controlled disturbance reserves are used when the frequency leaves the lower limit of normal operations (49.9Hz). Both contracted automated load shedding and governor controlled generation can be used. The response time is 5 seconds for activating 50% of the reserve, with 100% of the reserves activated within 30 seconds. Telemetry requirements are in line with those for frequency-controlled operating reserves [Nordel 2005a].

[35] One third of this requirement can be purchased from other member TSOs within the synchronized Nordic System, while two-thirds must be located within each national network.

Fast active disturbance reserves and *slow active disturbance reserves* are used to progressively replace and restore frequency-controlled operating and disturbance reserves. The fast active disturbance reserves must have 15 minute availability to restore the frequency responsive operating and disturbance reserves, while slow active reserves may take up to 4 hours to come on line. System operators secure fast and slow active reserves through bilateral agreements or from their own reserves. Reserves resources generally consist of gas turbines, thermal power plants, hydropower and load shedding. Active disturbance reserves are called upon infrequently; just three times in the past five years (Statnett 2006).

B.3 Demand Response in Nordic Power Markets

Demand response plays an integral role in the Nordic schemes for balancing and regulation. Demand response resources are considered full substitutes for generation resources, provided they meet the same requirements concerning size and activation time. The five Nordic TSOs currently utilize more than 3,500 MW of demand resources in their mix of operational reserves (see Table B-4). The full potential of demand side participation of all types has been estimated at about 12 000 MW in total – equal to 20% of the peak demand across the Nordic region.

	Denmark	Finland	Norway	Sweden	Nordic Region Total
Peak Demand	6,250	13,500	20,680	27,300	67,800
DR Contracted by TSOs	25	365	1,300	385	2,075
Non-Compensated and Other DR[36]	20	140	800	700	1,660
Estimated Total DR Potential	500	2,500	5,000	4,000	12,000

Table B-4: Current and Potential DR Participation in Nordic Countries, MW (Nordel, 2004)

At the regional level, Nordel regards demand response as a critical "pillar' of the interconnected Nordic power system's overall reliability. In its recent report on peak load mechanism, Nordel proposed a uniform monitoring and data reporting approach for demand response performance [Nordel 2005b]. Nordel has also formed a demand response working group to collaborate in implementing the individual Nordic TSO national action plans for the promotion of demand response, as well as participating in international projects on demand response. As part of this collaboration, each TSO has developed an action plan for enhancing demand response, including estimating DR potential and monitoring and evaluating demand response contributions. The status of demand response in providing reserves and regulation at the national level is described below.

B.3.1 Demand Response in Norway

Norway has made the most progress towards incorporating loads into its everyday balancing and regulation operations. Statnett acquires much of its operational reserves from contracts set through a weekly bidding process (the Reserves Option Market, RKOM). Statnett has also

[36] Non-compensated Demand Response consists of frequency-controlled loads, usually very large industrial customers, who are subject to disconnection during system disturbances as a condition of service. Other observed demand response includes retailer rate programs such as TOU.

entered into some long-term contracts (5-10 years) with some generators. The amount of the acquired DR resources varies weekly Figure B-5) and in many weeks DR comprises most of the total regulating power turnover [Stattnet 2005b].

Statnett's DR action plan proposes acquiring an additional 260 MW of demand response through both tendering and bidding. Statnett is focusing on medium-size end-users (See Box 1) and independent aggregator, as research suggests their opportunity costs for participation may be lower than for large industrial end-users.

Highlights of Statnett's DR strategy include:

- *Conducting frequent auctions for regulating reserves regardless of current need.* Statnett conducts auctions for regulating reserves even if the need is not very great. This way the end-users stay in practice and stay engaged. For many bids the offered volume may be much higher than the purchased volume. Statnett's philosophy is that proper market functioning requires prices based on marginal costs and maintaining a high market volume [Statnett 2005e.]

- *Take into account the customer's ability and limitation to perform.* Most loads are limited in their ability to perform. Smelters, for example, cannot be controlled for more than four hours. Loads that cannot interrupt for the entire four hour period or cannot operate at the required frequency receive a downward adjustment in the price-per-MW paid to them. The formula for doing this is specified in the tariff, and the adjustments take place as part of the weekly bidding process.[37] [Statnett 2005e]

- *Encourage third party aggregators and multiple business models.* Most of the 1200 MW of demand bid into the RCOM each week comes from large industrial customers, typically aluminium smelters, metal processing, and the forestry, pulp and paper industry. However, the program is flexible enough to accommodate other types of loads, including blocks of load bid in by aggregators focusing on particular responsive demand niches. Promising niches include large electric boilers, especially if they have oil-firing capability (see Box 1), customers with back-up or emergency generators (see Box 2); and medium-sized customers with controllable loads that can be aggregated.

- *Minimize rules and requirements.* Statnett does not require loads to meet the same stringent communications and telemetry requirements as generators. A common communications modality is interval meters and internet-based communications systems (ICBS).

[37] Minimum requirements apply to all loads, however. All loads must be capable of delivering a minimum of one hour load curtailment. Reserves must be available between 6 am and 10 pm each weekday and the minimum volume accepted is 25 MW

Nordisk Energikontroll is a small but well-known energy firm specializing in energy management for small industry and commercial buildings. Since 2004 they have been active third party aggregators in the Norwegian electricity market, specializing in large boilers capable of operating with either oil or electricity. The preferred operating mode of these boilers is with electricity; however, they are capable of switching back and forth between electricity and oil on very short notice, using a web portal and wireless telemetry scheme.[38]

Current capability is an aggregate 10 MW of demand across 35 customers, with plans to grow to 50 MW by 2006 depending on how oil prices trend. Average size of the boilers is 300 kW to 1 MW. Boilers can switch over in seconds, but the RCOM balancing market requires response within 15 minutes. Nordisk Energikontroll constantly monitors the demand drop capability of participants, and both Stattnet and the end-use customer's Energy Services Provider can monitor this status via a shared web portal. Electricity demand drops are dispatched by Nordisk Energikontroll upon Stattnet request.

Nordisk Energikontroll submits their option price bid (MW quantity and price) into the RKOM auction on a weekly basis during the five winter months. The option price bid includes associated costs (fuel, labor) should the option be called. The weekly option price bids vary significantly according to both electricity and oil market conditions, but typical values are in the range 1000-2000 NOK/MW (US$150-300/MW per week). With these market conditions it is possible over the course of a winter to accumulate 300,000 NOK in turnover, or about US$45,000 annually. If the option is called, Nordisk Energikontroll has arrangements with the Energy Services Provider who, as the market participant, receives the spot price for the amount of electricity curtailed. However, there have been very few (less than three) instances since market inception that their option has been called.

The total compensation is settled on a weekly basis according to individual contracts between the aggregator, the Energy Services Provider, and the end-user. Details of shared savings are covered in bilateral contracts between the end-user, the aggregator and the Energy Services Provider. In addition to monitoring their capability on a continuous basis, Statnett tests the operation of the system at least once a month.

Box 1: Aggregating Electric Boiler Load for the Regulating Power Market [Nordisk Energikontroll 2005]

Demand response for regulation and reserves is on a modest uptick in Norway. Large industrial customers initially had some difficulty in understanding and undertaking dispatched energy reductions; however, the current attitude has evolved into "show me the money and we can work together". Medium-sized factories and buildings in particular are more receptive, as they balance their operating and energy budgets (see Box 2). The difficulties with smaller customers are greater, as there is more need for investment in enabling technologies, more technical problems, and greater transaction costs. Evaluations suggest that participating loads look for predictable revenues, acceptable technical requirements, and acceptable (e.g., low) risk of being operated [Statnett 2005e].

[38] This is a common operating scheme in Norway for thermal loads, as electricity produced from hydroelectricity is cheaper than oil or gas except during drought-induced electricity shortages. Norwegian regulation obliges network companies to offer special tariffs for customers operating electric boilers with an optional fuel source available.

EffectPartner is a Norwegian energy consulting and project development company. They have worked with grid companies all over the Nordic region on power development projects, including a 2005 agreement with Eltra to relocate a 25 MW gas turbine from Norway to Esbjerg Harbor that provided regulation and reserves for the Danish grid.

In Norway EffektPartner has configured some 20 MW of emergency generator power for bidding into the Reserve Capacity Options Market (RCOM). EffektPartner enters into agreements directly with end-users who own emergency generator assets (usually diesel engines), which are typically telecommunications companies and industrial facilities. They operate on a shared savings approach, usually a 50-50 split. Cost of the diesel fuel during actual or test operations are paid for by the grid operator.

Participants whose bids are accepted into the weekly or monthly RCOM auction and whose options are called get compensated for their electricity reductions based on the imbalance market price (NOK/kWh). Typical standby bid prices in Norway could be 40,000 NOK/MW for the entire winter season. EffektPartner has participated in the RCOM market for three years, and other than test events their option has not been called. When called the generators must be turned on within 15 minutes. Duration of the event is typically 1-2 hours. Generators can be called no more than twice per day, and require an 8 hr “resting time” between operations. The outlook for emergency generators providing standby regulating reserves is quite positive in Norway, as plans to install large amounts of wind capacity will likely drive up the volume of regulating reserves procured through the RCOM market.[39]

Box 2: Back-up Generators Aggregated to Provide Demand Response [EffectPartner 2005]

B.3.2 Demand Response in Denmark

The Danish TSO has declared demand response a national priority for the security of the electricity supply and infrastructure. New targets of 150 MW demand response and 75 MW of emergency generators have been set for 2010, with this demand response capacity to be utilized partially as reserves and partially in the day-ahead Elspot and hour-ahead Elbas markets. The two Danish networks have slightly different priorities for demand response. West Denmark is increasingly burdened to provide more regulation reserves, as growth in wind generation requires significant reserves capacities to counteract fluctuations in wind turbine output. The Danes also hope an infusion of demand resources would increase the competitiveness in the reserve markets, currently dominated by just a few providers. In East Denmark, the anticipated de-commissioning of a large power plant in 2008 has generated interest in utilizing demand response resources for peak load reductions as well as for operating and disturbance reserves.

[39] Wind power is an intermittent power source; therefore, a growing volume of wind power will create the need for more regulating reserves to offset bulk power supply fluctuations.

B.3.2.1 Danish Pilot Projects

In 2004 Elkraft launched large industrial and small residential pilot projects in order to analyze the barriers to increasing demand response participation in the market. The industrial pilot has signed up 17 MW of back-up generation and 3 MW of DR resources to be used as fast active disturbance reserves.

The back-up generation load resource consists of individual generators in the 500 kW size range located in 26 large facilities (hospitals, computer center, airports, telecommunications or commercial customers (e.g., frozen goods warehouse, public ice arena). These generators can be remotely activated and offered for regulation and balancing power needs, meeting the 15 minute activation time required [Elkraft 2005]. The 3 MW of load-based DR comprises mainly large industrial customers. The TSO relaxed the lower size limit on any single reserve resource, thus allowing aggregation, in order to accommodate smaller loads. However, each resource within an aggregated load block has to be metered to verify performance, although on a day-after interval metering basis rather than the stringent SCADA requirement.[40]

Participating customers are compensated with a fixed capacity payment and an energy payment for the energy displaced whenever the resource is activated. The capacity payment was competitively bid in a tender process and averaged about $30,000/MW/year. The energy payments were based on the Elspot prices at activation and averaged about $150/MWh. The TSO reported significant interest in this program, particularly by backup generator owners, because of the attractive reservation payments [Elkraft 2005b].

Both the load resources and the metering and telemetry systems worked reliably during the trial. The backup generators and the load reductions were activated within one minute of dispatch, which is significantly shorter than the 15 minute requirement. There was some difficulty in determining performance of load customers during short (less than one hour) activations.[41] The TSO expects the pilot project will made permanent, satisfying part of its 2010 DR target of 150 MW. The TSO also will pursue further expansions of DR resources for disturbance reserves [Elkraft 2005b].

B.3.2.2 Other Danish DR Activities

The TSO is currently working on a new set of rules for simplified settlement procedures for regulating power supply from the demand side, which will also allow non-balance responsible parties to aggregate demand side bids for operational reserves. This is expected to boost DR participation in the tenders for operational reserves in Denmark. Finally, the TSO is working with the largest electricity consumers on the network, trying to encourage their participation in the DR tenders [Elkraft 2005b].

[40] A drawback of this approach is that the system operator does not have direct feedback on the response and performance of the demand resource.
[41] The hourly meter reading limitation resulted in any activation less than one hour creating ambiguous results

B.3.3 Demand Response in Finland

Fingrid has been quite active in encouraging more uptake of DR in its markets. In 2004, Fingrid undertook an extensive review of DR potential in the country and concluded that large industry alone (See Figure B-6) could provide 1210 MW (Pulp and paper – 790 MW; Basic metals – 320 MW; Basic chemicals – 100 MW) of demand response, equal to 9% of national peak demand.

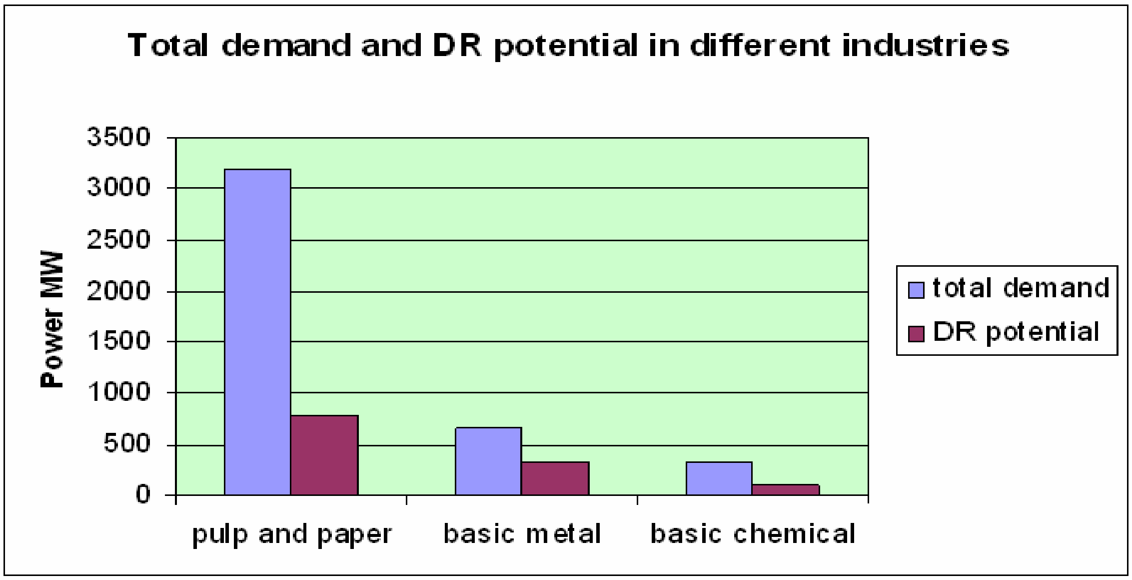


Figure B-6: Estimated Demand Response Potential in Finnish Industry [Fingrid, 2005b]

Fingrid has moved aggressively to access DR potential across all sectors, and has contracted DR resources of all types amounting to approximately 1000 MW. Fingrid has entered into long term bilateral contracts to ensure access to these resources in the long term. The bids from demand resources received in Fingrid's annual tendering process amounted to a bigger capacity than required, a clear signal of available DR resources [Fingrid 2005d].

Demand response in Finland is concentrated in large individual industrial customers, typically primary industry, heavy metals, and forest and forest products. As of 2005, there were 7 large customers providing 120 MW of frequency-controlled disturbance reserve and 400 MW of fast active reserves. The balance of the 1000 MW of load under contract is available on a temporary basis. Fingrid obtains day-ahead forecasts of reserve volume, as well as load status data (at 3 minute intervals) on all participating loads, and active power data on the bid-in reserve resources. Performance by these larger industrial end users has been strong, with no compliance issues, no notification problems, and generally positive performance to called events (Fingrid 2005d).

All participants bidding into the Reserves market are compensated equally based on an agreed availability of their load of approximately 7000 hours each year. The fixed fee is 1,500 € per MW. For loads wishing to subscribe on an hourly basis, the compensation is 0.3 € per MW for each hour of agreed availability. Loads are also compensated on a per-event basis for disconnection at a rate of 500 € per MWh. Resource owners must enter into long-term contracts (5-10 years), which has been a difficulty for some participating loads but desirable for others.

Fingrid's expects that demand response for operating reserves and regulation will increase because a very large (1600 MW) nuclear power plant will be commissioned in 2009. Such a large generator addition will increase requirements for synchronized reserves in order to maintain compliance with reliability rules. Fingrid and the demand resource owners under long-term contracts have agreed to develop a separate system protection scheme relying on load shedding that will accommodate the increased reserve requirements of the nuclear power plant addition [Fingrid 2005d].

B.3.4 Demand Response in Sweden

Sweden has an embryonic market for frequency reserves with no participation by demand side resources as of 2005. However, SvK as a public authority is empowered to set regulations and conditions of service for consumers, and has set forth conditions for larger load resources to provide frequency-activated reserves. These customers (predominantly industrial customers and large electric boilers of district heating systems) must shed their loads at four frequency steps between 49.4 Hz and 49.1 Hz, depending on the size of the unit and the duration of the frequency drop. The total technical load reduction potential of just electric boilers is estimated to be above 500 MW, exceeding SvK's total frequency-controlled disturbance reserve requirements. However, because of the fuel switching capabilities[42] of the district heating systems not all electric heater resources are available at any given time (Svenska Kraftnat 2005). It is likely in the future that the nascent frequency reserves market might replace the need for administrative procurement of frequency reserves services through condition of service requirements, thus providing a new market for loads capable of fuel-switching or rescheduling.

In addition to acquiring operational reserves, SvK is required by law to centrally procure peaking resources. DR resources are considered on equal terms with peaking generation to satisfy this legal requirement. SvK has entered into bilateral contracts with end-users totaling 141 MW for the winter period 2004/05, with 26 MW contracted with local stand-by generators. The contracted amount varies yearly according to need (e.g., the contracted amount was 440 MW in winter 2003/04). The temporary law is valid until the end of February 2008.

Sweden is focused on the post-2008 period, when the SvK's obligation to secure 2000 MW of peak load reserve will run out. The main focus has been on the development of new market designs that will utilize market principles to assure system adequacy and reliability of the power system. Sweden's action plan to enhance demand response includes consumer awareness building, research to explore the DR potential of residential electric heating systems, and economic analysis of demand response business models [Nordel 2005c]. It is hoped that

[42] These large (greater than 5 MW) district heating schemes can quickly switch from electricity prices to oil or gas if prices are too high

these activities will position Sweden to scale up the share of demand response in the balancing market and in operating reserves provision for the post-2008 period.

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C. United Kingdom: Ancillary Services and Load Participation

C.1 United Kingdom's National Electricity Market

The United Kingdom (UK) was one of the first countries to restructure its electricity industry. Under the terms of the Electric Act of 1989, the state-owned Central Electricity Generating Board (CEGB) was divided into the National Grid Company (NGC), responsible for transmission, and three generating companies.[43]

The cornerstone of the original restructuring was the English Power Pool. Each day, the Pool accepted bids from generators, and used cost-minimizing software to schedule loads and calculate a half-hourly System Marginal Price (SMP). This original Pool was a compulsory, day-ahead, last-price auction in which generators had transmission rights but no firm obligations to generate. System Operations, Market Operations (e.g., Pool Settlement), and Grid Operation were all supplied by National Grid Co. (NGC), and the Pool operated under a binding legal contract (the Pooling and Settlement Agreement).

In the initial period after market restructuring, National Power and PowerGen were in effect a duopoly, as these two generators almost always (over 90 per cent of the time) set the pool price. Analysts and regulators became increasingly concerned about market concentration and regulators pressured for additional divestiture [Thomas 2001]. Over time, however, new entrants to the generation market gradually reduced generator concentration (see Figure C-1).

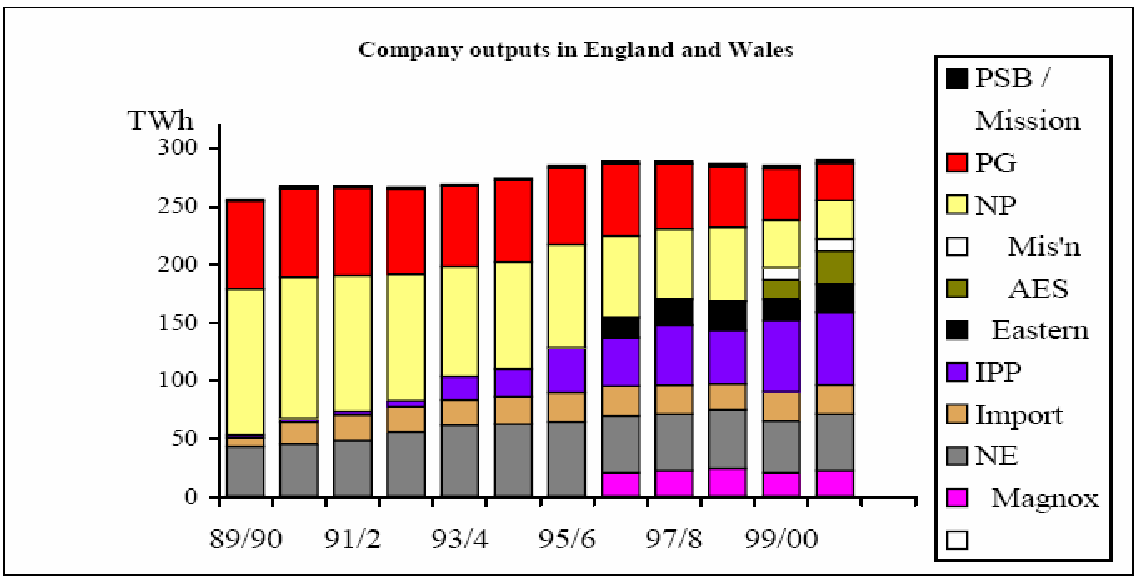

Figure C-1: Market Shares among Generators in the U.K. Market 1990-2000

The Office of Electricity Regulation (now the Office of Gas and Electricity Markets) conducted a major review of the market design in 1997 and concluded that complexities of price

[43] Two of the three (National Power and PowerGen) were subsequently privatized; the 20% nuclear share of the UK generation mix was kept in state ownership for several more years, as its nuclear reactors were believed to be too expensive to privatize.

formation in the compulsory day-ahead SMP auction system still allowed generators opportunities to exercise market power. The Pool Review recommended that the mandatory Power Pool be replaced by four voluntary, overlapping and interdependent markets operating over different time scales: bilateral contracts markets for the medium and long run; forward and futures markets operating up to several years ahead; a short-term bilateral market, operating from at least 24 hours to about 4 hours before a trading period; and finally, a balancing market from about 4 hours before real time. The System Operator would trade in this balancing market to keep the system stable, and use the resulting prices for clearing imbalances between traders' contracted and actual positions.

The replacement market design, the New Electricity Trading Arrangements or 'NETA', was introduced in March 2001. NETA essentially implemented the market design recommended by the OFFER/OGEM market design review. Under the NETA, most power transactions are based on bilateral trading of electricity contracts between generators, suppliers, traders and customers, thus reducing the opportunities for generators to exercise market power. Originally covering only England and Wales, with the passage of the Energy Act of 2004 [Energy 2004] NETA grew to incorporate the Scottish transmission networks, changing its name to BETTA (British Electricity Trading and Transmission Arrangements).[44] As of 2005, all of the UK except Northern Ireland is operated as one power system under the control of National Grid Company (NGC), the system operator.

Early results of the new market design are promising, as prices trended downwards from 2001 until recently. Analysts differ on whether the improved outcomes are due to the new market design or simply due to reduced supplier concentration in the generation sector. At the end of 2004 there were 37 major power producers operating in the UK [DTI, 2005]. These bilateral arrangements between generators, suppliers, and customers were also designed to provide greater choices for the market participants. By December 2004, about 42% of the electricity customers were no longer with their home supplier.

In 2004, the combined system has a total installed generation capacity of about 73 GW with a peak demand of about 61 GW [DTI, 2005a, b]. The total value of retail sales of electricity was estimated to be $28 billion [DTI, 2005c]. Total wholesale values were difficult to obtain because the majority of the trades (>90%) are performed through proprietary bilateral contracts.

National Grid Company (NGC) operates the transmission grid in England, Wales, and Scotland, which deliver power to10 major distribution systems (see Figure C-2).

[44] Prior to BETTA, Scotland was served by two vertically integrated entities (ScottishPower and Scottish & Southern Energy), who retained their interest in the generation, transmission, and distribution supply.

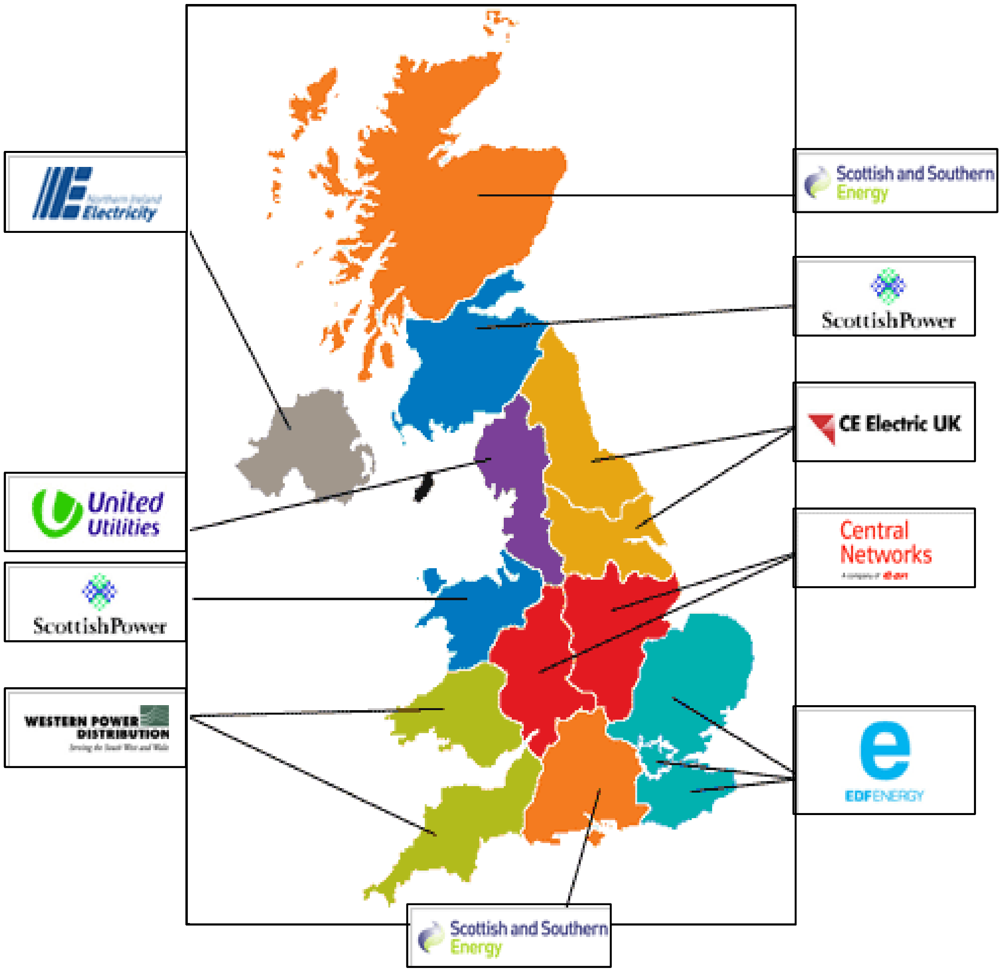

Figure C-2: UK Electric Grid Regions and Major Supply Entities

C.2 Market Design and Operations

The British power market under BETTA is strictly an energy commodity market, with provisions accommodating bilateral long-term contracts, bilateral day-ahead trading, for forward and futures markets extending months to years ahead, and a small imbalance market. Almost all electricity (>90% of the wholesale market) is bought and sold by bilateral contracts between buyers and sellers in over-the-counter markets or in power exchanges such as the London-based UKPX or other European power exchanges (e.g., APX or EEX). Additional generation (or load) capacity is procured for use as Balancing Reserves, Standing Reserves, and Frequency Response under NGC's Balancing Services umbrella.

Generators self-dispatch their plants rather than being centrally dispatched by the System Operator. There are three stages to the wholesale market, including settlement, which are illustrated in Figure C-3.

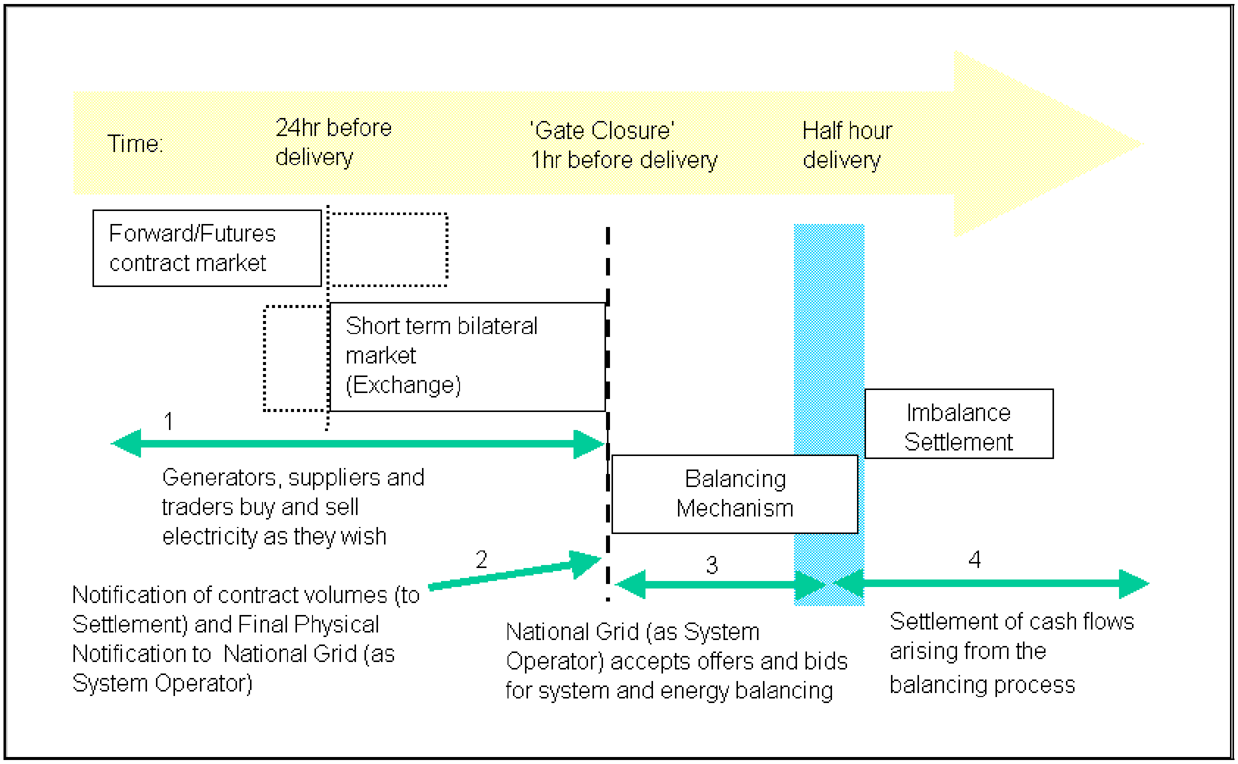

Figure C-3: Overview of BETTA Market Design [NGC, 2005]

C.2.1 Forwards and Futures Contract Markets

The bilateral contracts markets for firm delivery of electricity operate from a year or more ahead of real time (i.e. the actual point in time at which electricity is generated and consumed) up to 24 hours ahead of delivery. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver or take delivery, of a given quantity of electricity for an agreed price at a specified day and time. The Forwards and Futures Contract Market is intended to reflect electricity trading over extended periods and represents the majority of trading volumes. Although the market operates typically up to a year ahead of real time, trading is possible up to one hour ahead of delivery (Gate Closure).

C.2.2 Short-term Bilateral Markets (Power Exchanges)

Power Exchanges operate over similar timescales, although trading tends to be concentrated in the last 24 hours. The markets are in the form of exchanges where participants trade a series of standardized blocks of electricity (e.g. the delivery of any amount of MWh over a specified period of the next day). Power Exchanges enable sellers (generators) and buyers (suppliers) to fine-tune their rolling half hour trade contract positions as their own demand and supply requirements firm up. The markets are firm bilateral markets and participation is optional. One or more published reference prices are available to reflect trading in the Power Exchanges.

C.2.3 Balancing Mechanism

The Balancing Mechanism operates from Gate Closure to real time and ensures that supply and demand can be continuously balanced in real time (see Figure C-3). The System Operator acts as the sole counterparty to all Balancing Mechanism transactions. Participation in the optional Balancing Mechanism involves submitting ‘offers’ (proposed trades to increase generation or decrease demand) and/or ‘bids’ (proposed trades to decrease generation or increase demand). The mechanism operates on a ‘pay as bid’ basis. NGC purchases offers, bids and other Balancing Services to match supply and demand and resolve transmission constraints, thereby balancing the system in a manner consistent with operational standards and limits.

There is no spot price for the two half-hour imbalance energy markets. Prices are set by using the averaging of the energy bids and offers, respectively; not at the marginal price [Hunt, 2002]. This yields a single system buy and system sell price. Prices for balance energy are valid for the entire the BETTA system, omitting locational energy pricing methods. Network constraint management is settled via transmission charges, separate from energy settlements.

As the market moves towards the Balancing stage, NGC needs to be able to assess the physical position of market participants to ensure security of supply. To this end, all market participants are required to inform the NGC of their net physical flows in both the Forwards and Futures Contract Market and the Power Exchange. Initial physical notifications (IPNs) are submitted at 11.00AM at the day-ahead stage and are continually updated until Gate Closure (FPNs).

C.2.4 Imbalances and Settlement

Power flows are metered in real time to determine the actual quantities of electricity produced and consumed at each location. The magnitude of any imbalance between participants’ contractual positions (as notified at Gate Closure) and the actual physical flow is then determined. Imbalance volumes are settled at either the System Buy Price (SBP) or System Sell Price (SSP), depending on whether the seller or buyer is long or short.

C.3 Ancillary and Other Services Markets

Ancillary and “Other Services” are part of the Balancing Mechanism and are procured from both authorized electricity operators (AEOs), who own and operate generators, and other commercial entities, generally load customers or aggregators with backup generators and demand response resources.

Table C-1 summarizes ancillary and other services in the U.K. market, including type of product, eligible service providers, payment arrangements, and market size and annual value. The total value of ancillary and other services is $314M per year, which is about 1.1% of the total electricity market. Customer loads are only eligible to provide frequency response and reserve services, either as a direct customer or as part of a load block aggregated by a retail provider. From a technical point of view, it is difficult for customer loads to provide other ancillary services (reactive power support, fast start, and black start). The fast start units are gas turbine units that start rapidly from standstill and are used as next-start units in a black start scheme.

	Ancillary/ Other Service	Product	Eligible Providers	Payment Arrangement	System requirement	Annual Market Value (M$)
Provided by Generators and Loads	Frequency response	• Primary • Secondary • High • Low frequency relay for loads	• Large generators • **Load**	• Avail. Payments ($/MW/h) • Energy payments ($/MWh)	550 to 1260 MW	Mandatory • $34M. Commercial • $47M. **Total** • **$81M**
Provided by Generators and Loads	Reserve	• Regulating • Standing • Fast • Warming & Hot standby	• Large & small generators • **Load**	Regulating • BOAs **Others** • Availability ($/MW/h) • Energy ($/MWh)	Standing reserve: 2900 MW Fast reserve: 283 to 353 MW	Standing • $74M. Fast • $38M. Warming • $38M. **Total** • **$150M**
Provided by Generators	Reactive Power	Reactive Power	Generators NGC SVC[45]	Default • Utilization ($/MVAr h) Commercial • Utilization • Availability ($/MVAr /h)		Default • $29M commercial • $31M **Total** • **$60M**
Provided by Generators	Fast start	Fast start	Gas turbine	Availability		• $5M
Provided by Generators	Black start	Black start	Gas turbine	Availability		• $18M

Note: Market values include England and Wales only; Scotland is excluded. An exchange rate of $1.8=1£ is used.

Table C-1: Ancillary and Other Services Characteristics and Market Size [DTI, 2004]

NGC whenever possible seeks competitive procurement of ancillary services. This typically involves issuing tenders that document the terms and conditions of the service sought.[46] NGC selects the lowest cost bid meeting the contract requirements. For services with insufficient competition, NGC will negotiate bilaterals contract with individual service providers.

The procurement guidelines are generally inclusive of frequency response products from demand-side providers and reactive power and fast and standing reserves and frequency response products from small generators. NGC is interested in attracting more demand side resources into existing market structures or developing new ancillary and other service products that will utilize emerging demand/load management approaches. NGC conducted a pilot project in 2004-2005, called Demand Turndown, in order to gain more knowledge about the performance characteristics of demand side resources.

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[45] NGC SVC: National Grid Company Static Voltage Compensator owned by NGC.

[46] Guidelines are established under Standard Condition C16 of the Transmission License. Most recent guideline is version 4.2 released 1.1.2005. Available at http://www.nationalgridinfo.co.uk/balancing/mn_transmission.html. Tenders are issued on a monthly, 6-month, and annual basis depending upon the services sought.

C.3.1 Frequency Response Services

System frequency is determined by the balance between aggregate system demand and total generation in real time. Frequency falls when demand is greater than generation and rises when generation is greater than demand. NGC has a statutory obligation to maintain system frequency within ±1% of 50Hz (±0.5Hz) (see **Error! Reference source not found.**).[47]

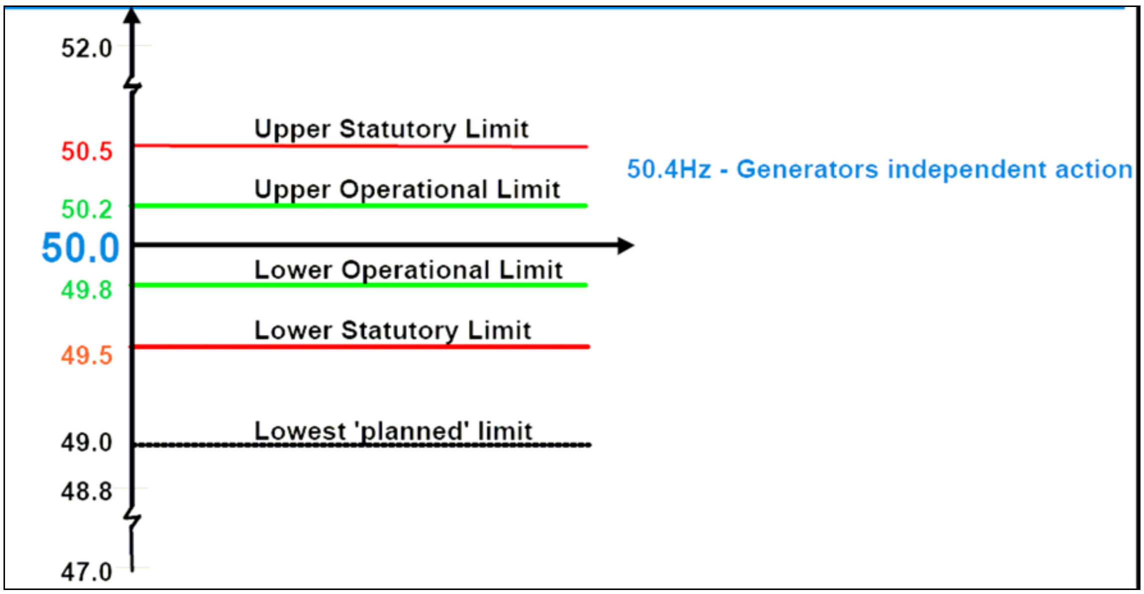

Figure C-4: Frequency Control in the UK [Morfill 2005]

All large generators must provide a certain level of frequency response as a mandatory service. The Grid Code specifies the requirements for frequency response (see Table C-2), including frequency response requirements differentiated by response time (e.g., how quickly a generator or load responses) and response duration (e.g., how long the response must be sustained) [NGC 2004b].

Frequency Response	Response Time	Duration	Trigger frequency	Delivered by
Primary	10 sec.	20 sec.	At various discrete thresholds (49.8, 49.5, 49.2 Hz)	Generator through automatic governor control
Secondary	30 sec.	Up to 30 min.	At various discrete thresholds (49.8, 49.5 Hz)	Generator through automatic governor control
High	10 sec.	Indefinite	At various discrete thresholds (49.8, 49.5 Hz)	Only for high frequency excursions. generator, automatic governor control
Low frequency relay	0.5 sec.	Up to 30 min.	Can vary between 49.8 and 49.65 Hz	Loads equipped with under-frequency relay

Table C-2: Frequency Response Services

47 This is a much larger normal frequency operating range than in North America where frequency is typically maintained within ±0.035Hz

Low frequency relaying is significantly faster than either primary or secondary frequency responses, thus providing a significant value to the system operators in arresting a low frequency excursion due to loss of generation capacity. The low frequency relay trip level is set between 49.80 and 49.65Hz. Adjusting the frequency tripping level differently for different customers ensures that there is a progressive volume of frequency-responsive demand that can accommodate different types of contingencies. On average, load is curtailed about 30 times a year if the under-frequency threshold is set to 49.7 Hz [NGC 2001]. In 2001, the prices for frequency response averaged about \$3.5/MW/h for primary, \$4/MW/h for secondary, and \$0.9/MW/h[48] for the high frequency response services [NGC 2001a].

The sequencing of primary and secondary frequency-responsive reserves is shown in Figure C-4.

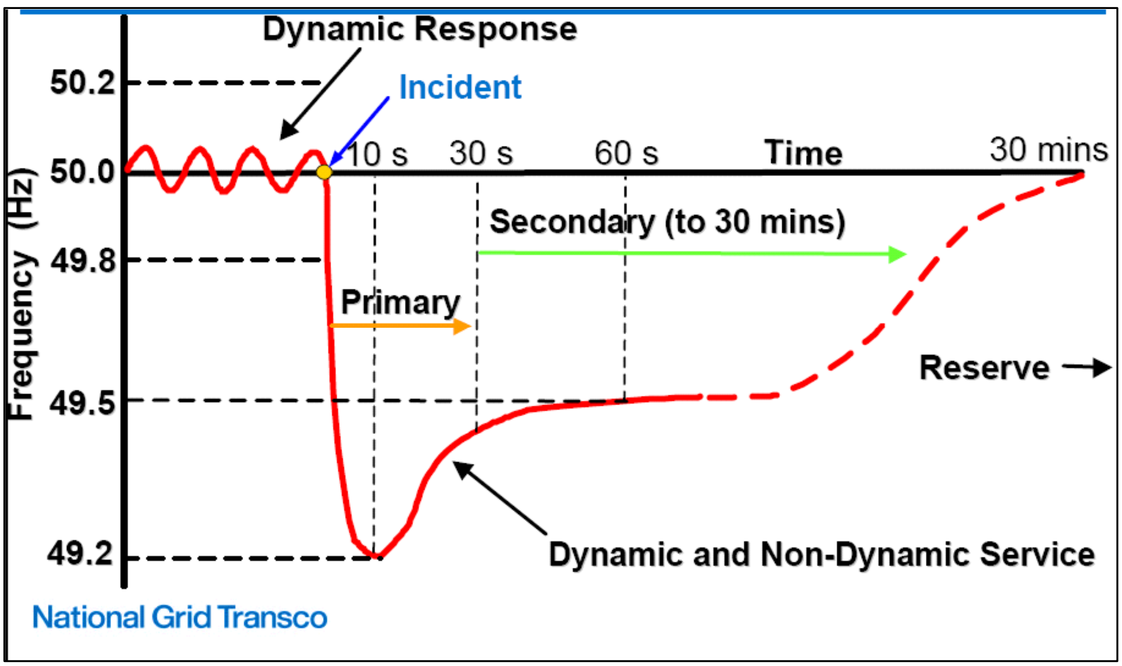

Figure C-5: Frequency Response Control Phases [Morfill 2005]

The system operator can also utilize high frequency response reserves, which serve to arrest and contain the rise in frequency following a loss of demand. Full delivery in 10 seconds represents the typical time that is taken for the frequency to rise by 0.5 Hz on the British Grid Systems for a demand loss of 1000 MW.

C.3.2 Reserves

NGC calculates the reserve requirements continuously from a day-ahead to real-time requirements and then optimizes the reserve procurement to achieve the most economic solution. There are four reserve services: regulating, fast, standing, and warming/hot standby reserves.

[48] An exchange rate of \$1.8=£1 was used.

C.3.2.1 Regulating Reserves

Regulating reserves are provided by generating units. Controlled by the system operator, the generator increases or decreases its power output on a second-by-second basis. This service is traditionally not provided by customer loads.

C.3.2.2 Fast Reserves

Fast Reserve is the rapid and reliable delivery of active power provided as an increased output from generation, following receipt of an electronic dispatch instruction from National Grid. Fast reverses are grid-synchronized resource, similar to spinning reserves in U.S. parlance. Active power delivery must start within 2 minutes of the dispatch instruction at a delivery rate in excess of 25 MW/minute, and the reserve energy should be sustainable for a minimum of 15 minutes. Fast Reserve is used, in addition to other energy balancing services, to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand. National Grid has a 24-hour requirement for Fast Reserve.

Customer loads can participate in this service; their response rate is generally faster than generators because load is typically dropped in one step. The amount of fast reserves is set by NGC for each month based on the reliability requirements and system inertia.

C.3.2.3 Standing Reserves

At certain times of the day, National Grid needs extra power in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand or generation less than forecast due to plant breakdowns. This requirement is met from synchronized and non-synchronized sources.

National Grid procures part of this requirement by contracting for Standing Reserve with service providers that utilize short notice generating units and load curtailments from customers.

The need for Standing Reserve is a function of the system demand profile and varies across the year, the time of week and day. National Grid splits the year into five seasons, for both working days (including Saturdays) and Non-Working Days (Sundays and most Bank Holidays), and specifies the periods in each day that Standing Reserve is required. Standing Reserve is currently contracted annually via a competitive tender process.

There are two types of agreements for Standing Reserve, depending on the type of service provider: a Balance Mechanism Participant receives only a reservation payment, while a non-Balance Mechanism Participant receives both reservation and utilization payments.

The forecast average availability payment for Standing Reserve during the period 1 April 2004 to 31 March 2005 (assuming 100% availability of all successful providers) is £4.14/MW/h for non-working days and £4.17/MW/h for working days.

C.3.2.4 Warming and Hot Standby Reserves

The warming reserve service was established to allow NGC to access generation plants that would not be available in the Balancing Mechanism because of their slow cold startup time.[49] The purpose of warming service is to maintain an adequate operating margin as contingent reserves. NGC offers 'warming' contractual arrangements to generators to facilitate their willingness to provide 'energy readiness' capabilities that can be converted into timely energy, synchronized reserves or frequency response services. Load customers are also allowed to provide this service.

Hot standby reserves are required under certain conditions when it is necessary to hold some generation in a 'state of readiness' to generate at short notice. Under these circumstances, fuel will be used or energy taken to maintain this state of readiness. NGC will offer 'hot standby' contractual terms to generators to facilitate their 'energy readiness' capabilities so that can be converted into timely energy, synchronized reserves or frequency response services.

C.4 Load Participation in Ancillary and Other Services Markets

Table C-3 summarizes the requirements, eligibility and amount of loads participating in Ancillary and Others Services Markets. During 2002/2003, loads provided about 29% percent of the total market for frequency response. The load contribution to standing reserves was about 10% of the total standing reserve requirements. Descriptions of how load participates in providing each ancillary and other service are provided below.

C.4.1 Frequency Response

NGC procures frequency response as a commercial service from demand side resources, which typically consists of load blocks contracted between customers and load aggregators. Size eligibility requirement is 3 MW or more for any individual load. The frequency threshold at which the relay disconnects the load is negotiated based on how often the load is prepared and willing to be disconnected. Historically, a setting of 49.7 Hz has yielded about 30 load shed events/year [NGC 2001]. On average, the load curtailments lasted between 15 and 20 minutes. NGC has provisions that allow the under-frequency relays to be disarmed when the load is unavailable, allowing an important reassurance to the end-use customer against unwanted interruption risk [Bailey 2003].

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[49] The Balancing Mechanism time horizon for economic dispatch is one hour prior to delivery, much shorter than the lead time for starting up a thermal unit.

Ancillary Services	UK Balancing Market and Service Requirements	Size requirements (MW)	Market Volume	Criteria for reserve activation	Is load participation permitted? YES/NO	Current load participation (MW)
Regulation	**1. Primary response** • Activated within 10 sec • Sustained for 20 sec	1000-1200 MW	9 TWh	Below 49.8 Hz and Above 50.2 Hz	Yes >=10 MW	Nil
Spinning Reserves (synchronized)	**1. Fast reserves** • Activated within 2 min • At ramp rate >25MW/min • Sustained for 15 min • >= 50 MW non-aggregated • >= 70 MW if aggregated • Procured monthly		2.7 TWh held 170 GWh used		Yes	Unknown
	2. Secondary response • Activated within 30 sec • Sustained for 30 min		10 TWh held		Yes	Unknown
	3. Low frequency Relay response • Activated within 0.5 sec • Sustained for 30 min			49.8 – 49.6 Hz	Yes	571 MW (2003/04) (29% of total)
Non-spinning reserves (non-synchronized)	**1. Standing Reserves** • Procured annually • Activated within 20 min • Sustained for 2 hours • At least 2 times a week (non-working days) • At least 3 times a week for weekdays • >=3 MW, can be aggregated • From non-sync resources	2000 MW	8 TWh available 85 GWh used (2002/03)		Yes	250 MW (2003)
Replacement reserves (non-synchronized)	**1. Warming and hot standby Reserves** • Required to maintain operating margins at a day-ahead time scale • Contractual arrangement to provide 'energy readiness' capabilities				Yes??	
	2. Demand Turndown Pilot		1500 activations/yr			163 MW

Table C-3: Ancillary and Other Services Requirements and Load Participation

Large industrial customers (e.g., cement works, gas separation plants, and arc furnaces) are primary demand-side providers of frequency responsive load. Arc furnaces typically have very lumpy consumption patterns, which leads to periods during which they are unavailable. However, when aggregated, arc furnaces can have a fairly predictably steady and flat load profile. The market potential of arc furnaces to provide frequency response is estimated at ~700 MW with a probability of 90% to be available [Bailey 1998]. Cement plants are estimated to have a resource potential of about 50-90 MW.[50] Among smaller industrial customers, additional resources include cold storage distribution centers and other types of industrial refrigeration. Load aggregators currently target this market sector because of their unique ability to drop significant load for refrigeration end-uses with very little impacts to their core business.

The first frequency response contract was established by Yorkshire Electricity Group in 1996, for approximately 50 MW. It involved large cement works with very stable loads [Bailey 1998]. In 2003, the available frequency responsive load was increased to 110 MW. Gaz de France, a demand response aggregator, aggregated 13 cement works site for this service. [IEA DSM 2003]. In terms of electric energy displacement, load side frequency response has increased from 2.6TWh to 2.8TWh in the period of 2002-03, which represents a 29% share of the total market for frequency response.[51]

C.4.2 Standing Reserves

The first standing reserve contract with load customers was executed by Yorkshire Electricity group in 1993 for steel mills and large cement plants.[52] In 2001, the total aggregated load resource for Standing Reserves was 250 MW. Customers that agreed to provide Standing Reserves have been attracted by the reservation payments and the relatively short load reduction periods (less then 20 min on average in duration) [Bailey 2003].

C.4.3 Demand Turndown Pilot Program

A demand response pilot program, called the Demand Turndown Pilot, was initiated in summer 2004. A primary objective of the Pilot program was to increase competition in the balancing services market by increasing the number of contingency reserve resources (i.e. customer loads) and to free up generation capacity for the energy markets or other reserve services. The pilot project was targeted to large customers with back-up generators and/or significant load reduction capabilities that could be aggregated by load aggregators in the Balancing Mechanism as warming reserve.

Load aggregators were required to bid a minimum of 100 MW over two specified time windows (9:30 am to 11:30 am and 11:20 am to 1:30pm, from April 5th through July 30th.). After the pilot commenced, NGC realized that the minimum size threshold of 100 MW was too high for load aggregators and NGC decided to relax and lower the size threshold.

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[50] Personal interview with Mark Bailey, Heads of Special Markets, Gaz de France, Leeds, UK on 12/6/2005.
[51] Cited at http://www.ofgem.gov.uk/ofgem/shared/template2.jsp?id=5743
[52] Personal interview with Mark Bailey, Heads of Special Markets, Gaz de France, Leeds, UK on 12/6/2005.

Two load aggregators (Gaz de France and Npower) participated in the initial pilot trial and enrolled seven customer sites. NGC's post-analysis of the initial trial showed that the Demand Turndown service was called 8 times (7 utilizations and 1 standby), mainly for trial testing purposes rather than for economic reasons. The average daily availability in the morning (window 1) and afternoon (window 2) window was 66 MW and 48 MW respectively for each aggregator.

Because of the low turnout, NGC revised the design of the pilot for the winter 2004/2005 to allow participating customers more flexibility in determining an option price associated with time windows during which their loads could be curtailed. This new program feature was made available in addition to the existing fixed time window product (9:00 a.m. to 11:00 a.m. for the winter).

The overall experience during both summer and winter seasons was disappointing in terms of participation levels among loads, and the Pilot was discontinued. Capacity payments to participating customers were relatively low, which contributed to the low initial subscription rates in the Pilot. With a reservation payment of about 5 £/MW/h ($9 /MW/h), the reservation payments were relatively small because of the limited hours of service (2 times the 2-hour time window per day). Expressed in terms of per MW per month payment, the reservation payment amounted to $1000/MW/month.[53].

C.5 Summary

The UK is one of the first countries to utilize load resources to provide frequency and fast reserves. Load aggregators have been successfully marketing eligible ancillary services to large industrial loads for more than 10 years. Key reasons for this early market participation was a source-neutral market and reliability rules that provided a level playing field for both load and generator resources. At present, load resources provide about 30% of the secondary frequency response service; this service is comparable to spinning reserves in U.S. wholesale markets. These load resources have under-frequency load shedding control strategies with varying frequency thresholds such that the loads will trip gradually. By establishing gradual load control over a range of frequencies below the desired set-point, the load resources offer functionality that is similar to the droop control of a generator (which increases the MW output as the frequency decreases). About 30% of the standing reserves are provided by load resources; this service is comparable to non-spinning reserves in U.S. wholesale electricity markets. Load aggregators have acquired significant insights into load characteristics and the design of the aggregated load portfolios for minimizing their risk of underperformance in providing balancing market services. Based on these experiences, UK load aggregators are now recruiting smaller industrial and large commercial customers with significant short-term load flexibility to increase their resource portfolio. Most of the new commercial targets have significant native thermal storage characteristics that would enable a site to curtail the cooling or heating load for a short period (less than one hour) without significantly impacting the core business of customers.

[53] Personal interview with Mark Bailey, Heads of Special Markets, Gaz de France, Leeds, UK on 12/6/2005.

A key lesson to be learned from the UK balancing market design is that the physical reliability functions required by the system need to be reflected in the market definition. For instance, to guard the system against large imbalances in cases of unplanned generator outages, the power system requires resources that respond to frequency. Hence, the market designers established a frequency response market with a set of performance requirements that provides this specific function without any pre-conceived source preference. The source neutrality established market conditions in which load resources have been playing a significant role in the balancing markets and, thus, improving the overall market competitiveness.

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