System Services International Review

Market Update

16010876

Prepared by KEMA Inc
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1. Introduction

1.1 Background

Within the SEM there is an ongoing need to provide and develop a meaningful portfolio of system services (AS) along with the technical, commercial and regulatory frameworks needed to support the provision of such services.

In 2007 KEMA was engaged by EirGrid to carry out a review of the AS regimes adopted in a number of international (island) markets. This involved an examination of what services were being used, why and how they were deployed and how the arrangements had evolved during the period that formalised AS measures had been established in the respective liberalised markets.

EirGrid has now asked KEMA to further augment their earlier study with more specific details of prevailing operating frameworks in each of the countries examined in a similar international review of current AS measures. In so doing it is envisaged that this subsequent study will be used to provide an insight into the various options that are in place internationally, the commercial frameworks that support them and their possible suitability for inclusion in the development of AS specific products for use in the Single Electricity Market (SEM).

1.2 Scope and Deliverables of this Report

As KEMA had previously provided assistance in this area it was agreed that the earlier study would be used as a suitable starting point for this deeper investigation. More specifically the scope of this work includes:

> A country specific review of products and services in Great Britain (GB), New Zealand, Tasmania, Singapore, Spain and Cyprus. In each case the key elements include:

- An investigation into what services are available, whether they are mandated or market driven and how they are procured;
- A description of the contractual / market arrangements currently in place in support of the services provided;
- An understanding whether minimum generation could be regarded as an explicit service anywhere and/or is it reflected in other AS products;
- An overview of the supporting commercial arrangements (e.g. balancing mechanism vs gross pool) and the performance incentives that may apply;

- A summary of applied penalty arrangements where the “causer pays” for services, either explicitly (e.g. for reserve) or implicitly (e.g. ramping cost due to variable resource captured in imbalances vs the SEM where it is a constraint cost); and

- Market specific revenue assessments i.e. the revenue generated in each case in relation to the overall market revenue.

> Finally a summary review of the appropriateness of each market’s activity in relation to Ireland and Northern Ireland’s key market service drivers, including capacity mix, availability and development of products and services and typical cost recovery mechanisms is included.

1.3 Structure of this Report

We have structured this Report as follows:

> Each of the 7 markets reviewed is addressed in a separate section from section 2 onwards and covers:

- Key underlying features of the system operating arrangements including generation, demand and the transmission network; and

- The system services observed, how they are applied and (where appropriate) what developments may be taking place.

> Sections 9 to 11 provide a comparison of the markets studied and considers their respective characteristics in relation to the current service arrangements in the SEM by highlighting key similarities, differences and some of the reasons how and why these arise.

> Section 12 provides key observations from the international review and finally section 13 delivers KEMA's summary conclusions.

2. Great Britain

2.1 Introduction and market overview

The Electricity Supply Industry was originally privatised in 1990 and has since undergone a number of major reforms to accommodate significant structural change. Much consolidation has taken place in the industry over the last 17 years and the market is now largely made up of 6 vertically integrated players i.e. companies with generation, trading and retail supply assets. There is full competition in supply and generation and forwards and futures markets have developed where a range of standard and structured products are bought and sold by suppliers, generators and trading parties. There are 7 Distribution Businesses, 3 transmission asset owning businesses and one System Operator responsible for system operation activities across Great Britain. These are regulated businesses that derive the majority of their income from the price controls set by the industry regulator Ofgem.

The market in England and Wales was originally set up to operate as a Gross Pool. However, initially there were two major power generators with significant market power and this caused concern as to whether the market was operating as efficiently and effectively as it could. This concern eventually led to the replacement of the Electricity Pool with the New Electricity Trading Arrangements (NETA) introduced in April 2001. NETA brought about a market where energy is traded like any other commodity, through bilateral contracts. The essential elements of NETA are forwards and futures markets, energy exchanges, a balancing mechanism and imbalance settlements.

In April 2005, NETA was expanded into the British Electricity Trading and Transmission Arrangements (BETTA) which introduced a single wholesale electricity market for the whole of Great Britain with a single transmission System Operator (National Grid) independent of generation and supply.

The UK Government's Electricity Market Reform (EMR) White Paper published in July 2011 sets out plans for the future decarbonisation and security of electricity supply – essentially helping to move the economy away from its carbon dependency while at the same time ensuring to 'keep the lights on'. Significant decarbonisation of energy supply is required if the Government's target of an 80% reduction in CO_2 emissions (pegged to 1990 levels) by 2050 is to be achieved. The Government's strategy for Market reform is to develop new systems and arrangements for:

- Long term contracts for low carbon energy generation in the form of Feed in Tariffs with Contracts for Difference (FiT CfD) that will provide clear, stable and predictable revenue streams for investors. These will include a Carbon Price Floor to reduce uncertainty, and an Emissions Performance Standard to limit carbon emissions from new fossil-based plant;

> An Institutional Framework for administering FiT CfD and contracting for capacity, possibly at arm's length from Government. This will also evaluate progress and future plans with a first review in 2016;

> 'Grandfathering', to support the principle of no retrospective changes to low-carbon policy incentives, all within a clear and rational planning cycle; and

> Improving Market Liquidity to help overcome barriers to entry and growth in electricity generation and ensure that there is enough market liquidity to enable independent generators of all sizes to compete effectively.

The estimated investment in electricity supply infrastructure is very significant, at up to £110bn by 2020, and it is expected that nuclear and renewable energy sources will benefit from an enlarged market having greater liquidity and fewer barriers to entry and growth. Additionally the Emissions Performance Standard (EPS) of 450g CO2/kWh means that new coal-fired power will need to adopt Carbon Capture and Storage (CCS) in order to be permitted; and in this context a flagship proposal, Contracts for Difference (CfDs), is potentially very attractive for investors in Low and Zero Carbon (LZC) Technologies. If adopted, this will help de-risk investment and effectively reduce the cost of capital, one of the key market barriers to increased take up of LZC.

2.1.1 Generation

The GB market currently benefits from a diverse mix of generation. 'Digest of UK energy' Statistic shows that coal and gas have the same percentage of installed capacity (29%), although the proportion of energy produced from gas is higher. Gas fired generation represented around 46% of production in 2010 and coal came in second at 28%. Looking forward it is expected that gas will make up an even higher proportion of output as the plant is newer and more efficient and would be expected to run as base load plant.

Electricity generation from renewable energy sources has increased by 15% to reach 9.2GW over the period from 2009 to 2010. There are over 27GW of additional (proposed) renewables projects with connection agreements up to 2020.

The aggregate transmission entry capacity (TEC) will rise significantly in forthcoming years (see Figure 1 below). An overall increase in contracted generation of 31GW is reported, over the period from 2011-2017. The introduction of the Large Combustion Plants Directive (LCPD) has required large electricity generators to meet more stringent air quality standards since 1 January 2008. This directive affects around 12GW of mainly coal and oil fired generators. Plant that has "opted out" of this obligation is scheduled to close by the end of 2015.

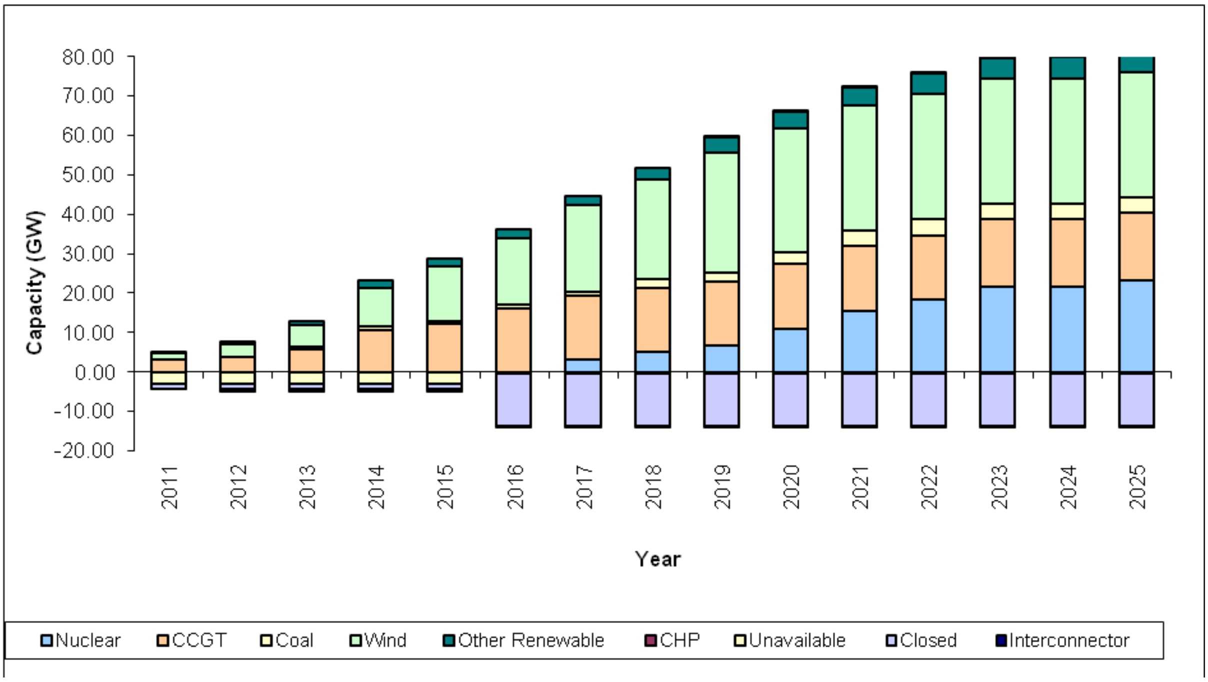

Figure 1: Changes in Generation Capacity, 2011/12 to 2025/26 (source: National Grid)

One important consequence of the current trading arrangements is a tendency for vertical integration as companies converge to hedge their risk. The GB market has evolved towards a position where generation ownership has changed to enable balancing of vertical integrated generation/supply portfolios to the extent that there are now six large vertically integrated participants that own large supply and production businesses; although not all of them are fully matched in terms of their hedging potential. In addition there are a number of relatively large independent generators, namely International Power, InterGen and Drax. These companies contract a significant proportion of their generation ahead to mitigate their exposure to short term price movement.

2.1.2 Demand

The GB Market has an annual consumption of around 380TWh with Peak Demand estimated by National Grid (NG) for Winter 2010/11 at 59.1GW. According to NG's Seven Year Statement (SYS), peak demand is projected to increase by 0.3% until 2017/18 and energy consumption in general (driven by modest economic growth) is forecast to be offset by growth in embedded generation, hence reducing growth in electricity transmission demand.

The average minimum and typical summer demands and typical winter and maximum winter demand for the GB market are given in the chart in Figure 2.

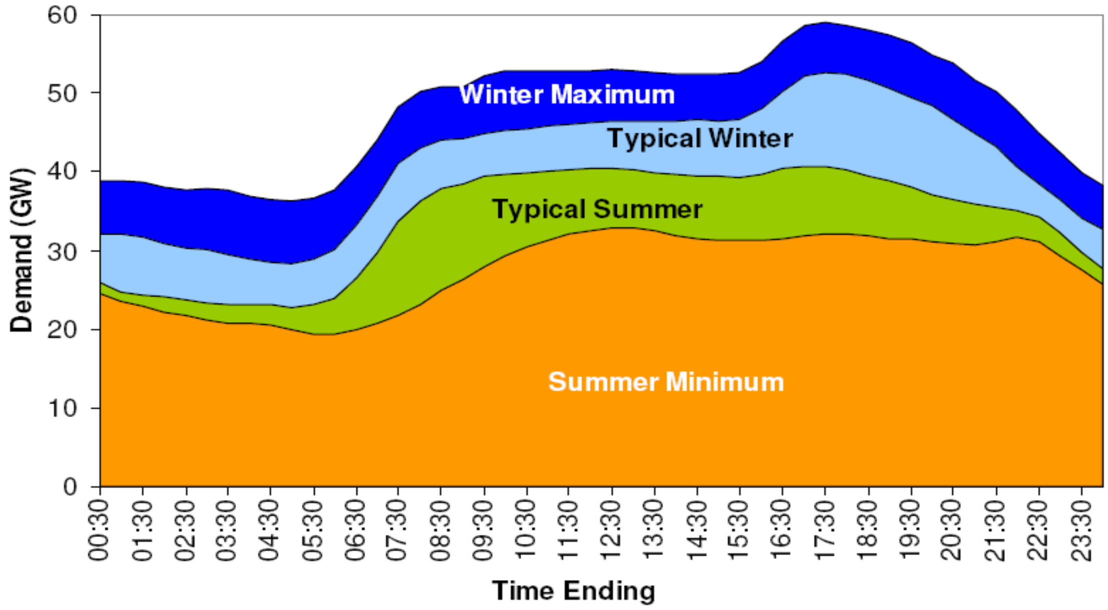

Figure 2: Summer and Winter GB Daily Demand Profile (National Grid SYS, figure 2.1)

The chart shows that Peak Demand is significantly higher in the winter. The peak periods are normally between 16:00 to 19:00 in the winter period and there are incentives (e.g. Triad charges provided by NG for large demand customers to minimise their demand at times of expected system peak.

Electricity use is split into the following customer groups (see Figure 3 below). Overall there are around 26m domestic connection points in Great Britain with around 2.5 million business customers.

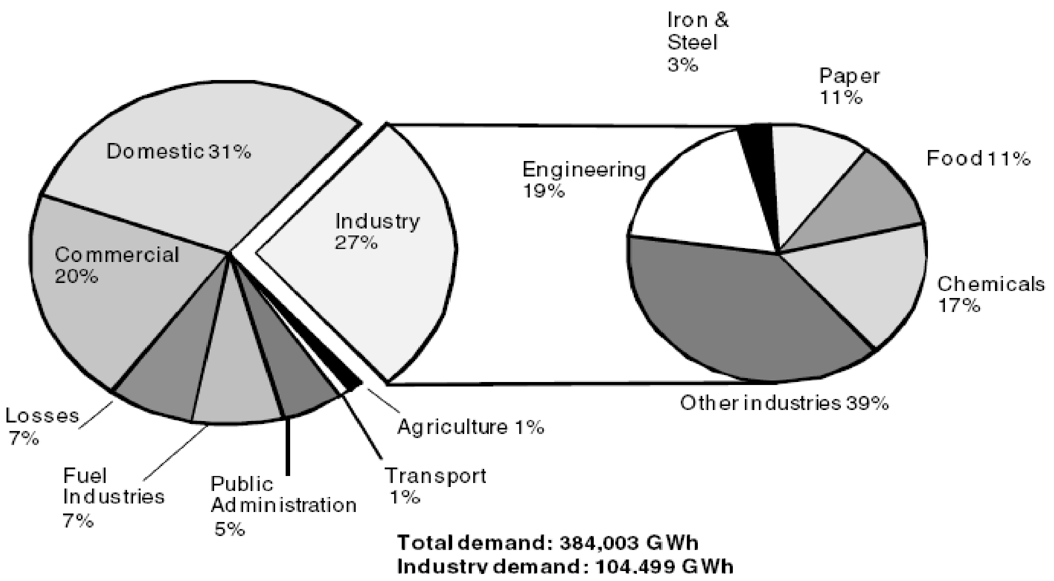

Figure 3: Electricity use in GB (Source: Digest of UK Energy Statistics 2011)

2.1.3 Transmission

The transmission system in Great Britain is made up of 400kV (super grid) and 275kV transmission grid systems (and 132kV transmission system in Scotland). In England and Wales the 132kV systems are managed by the local distribution network companies.

The GB transmission system statistics are displayed in Table 1, along with a system diagram illustrated in Figure 4.

Table 1: GB Transmission system properties

Voltage	Overhead lines	Cables	Substations
400kV	11,216km	166km	142
275kV	5,960km	498km	191
132kV & below	4,759km	210km	284
DC	n/a	463.5km [1]	n/a
Total	**21,935km**	**1,201km**	**617**

The majority of large power stations are directly connected to the GB transmission system. However, several large power stations are embedded within the lower voltage distribution networks. Medium (between 50MW and 100MW) and Small (less than 50MW) power stations are currently all embedded within the distribution networks.

Currently there are three HVDC external interconnections linking the GB transmission system with external systems in France, the Netherlands and Northern Ireland with combined capacity of 3500MW. Capacity on these interconnectors is offered for sale to eligible users (separately in both directions) through tenders and auctions, for varying contractual periods.

[1] This includes England-France interconnector (140km), Brit Ned (260km) and Moyle (63.5km)

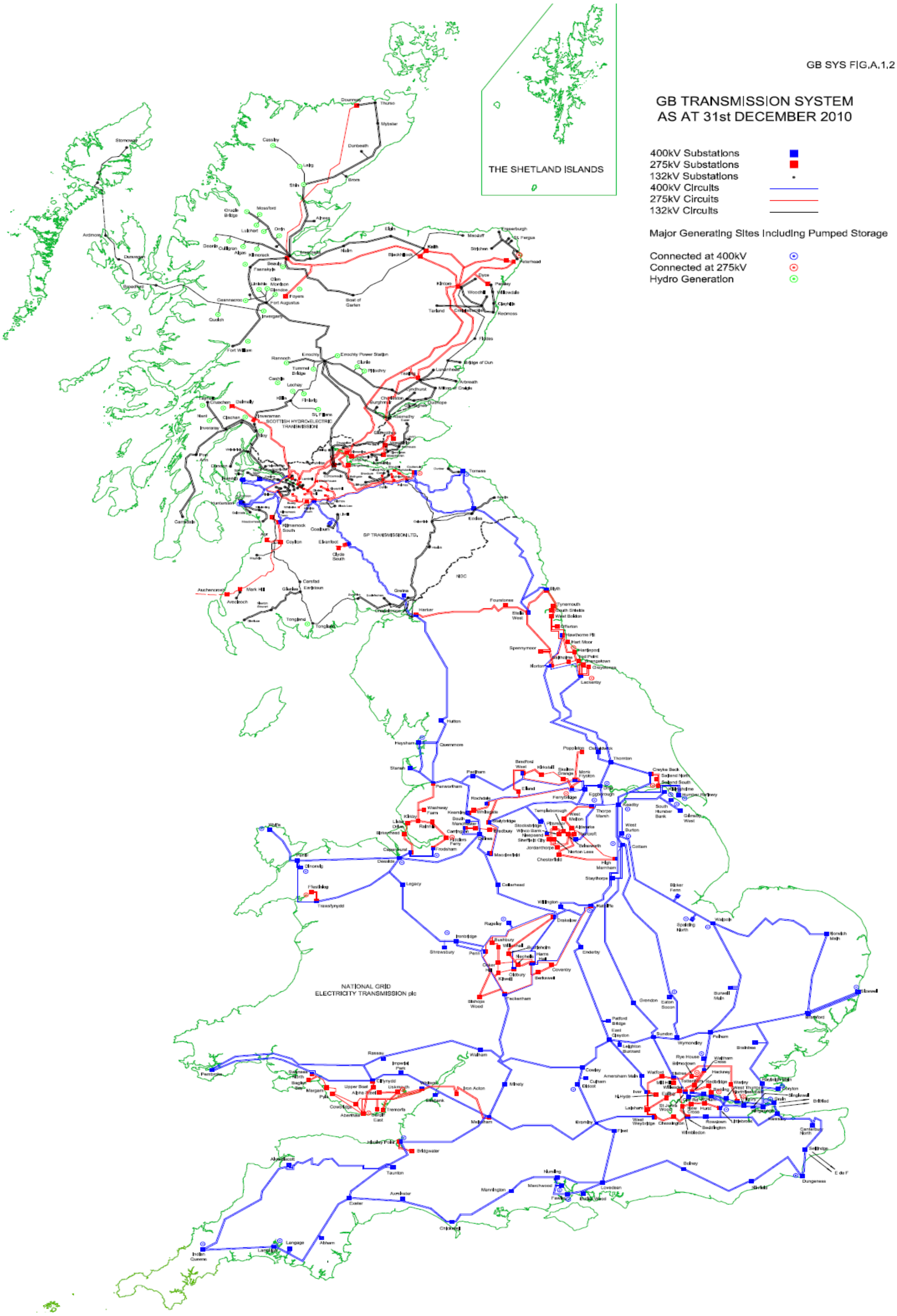

Figure 4: GB Transmission Network (Source: National Grid: 7 year Statement)

2.2 Services used by the GBSO

The services that National Grid needs to procure in order to balance the transmission system are referred to as Balancing Services where the Transmission Licence defines Balancing Services as:

- Ancillary or system services;
- Offers and bids made in the Balancing Mechanism; and
- Other services available to the Licensee's Transmission System in accordance with the Act or the Conditions.

Services are described in Connection Condition 8 of the Grid Code. Under the Code there are three categories detailing the services provided, these are designated as mandatory, necessary or commercial as in Table 2 below.

Table 2: Designation of GB system services

SYSTEM SERVICES		
PART I – Mandatory system services	**PART II – Necessary system services**	**Commercial**
> Reactive Power > Frequency Response	> Fast Start > Black Start > System to Generator Operational Intertripping	> Enhanced reactive > Firm frequency response > Reserve – • Short Term Operating reserve; • Fast Reserve; • BM Start Up (Warming) > System to system services including Emergency Instruction > Maximum generation > Commercial Intertrip/ Energy Management Systems > Constraint Management

2.2.1 Frequency Response

The System Operator has a licence obligation to control frequency within 1% of normal system frequency of 50Hz as specified in the "Electricity Supply regulations". In order to meet this requirement the SO must ensure that sufficient response is maintained to manage all credible circumstances that might result in change of frequency. The requirement covers response to minor imbalances between demand and generation (dynamic frequency response- provided continuously), and larger imbalances, say for instance, when a large generating unit fails suddenly (non dynamic frequency response- initiated at pre-defined frequency excursion).

In order to meet the requirement for frequency response National Grid employs three separate mechanisms:

Mandatory Frequency Response – This is a mandatory service provided by large generators (>100MW) to automatically change their active power output in response to a change in system frequency. It represents an automatic change in active power output from the Balancing Mechanism Unit (BMU) in response to a change in the system frequency. The service, as provides for the operation of a BM Unit in accordance with Grid Code CC 6.3.7 and BC 3.5, under normal operating conditions with the speed governor set so that it operates with an overall speed droop of between 3% and 5%. All such generating units must be capable of providing continuous active power response through their automatic governing systems Each BM Unit is required to provide, for any Frequency Deviation and at any level of De-Load, at least the amount of Primary Response and/or Secondary Response and/or High Frequency Response, all of which are set out in the relevant Frequency Response Capability Data tables in the relevant Mandatory Services Agreement. When a unit delivers the service, the total payment consists of two elements:
A Holding payment (£/h); Made for the capability of the unit (availability) to provide response when the unit has been instructed into responsive mode. BMU's submit holding prices on a monthly basis. Details of frequency response holding in 2010/11 are shown in Figure 5.

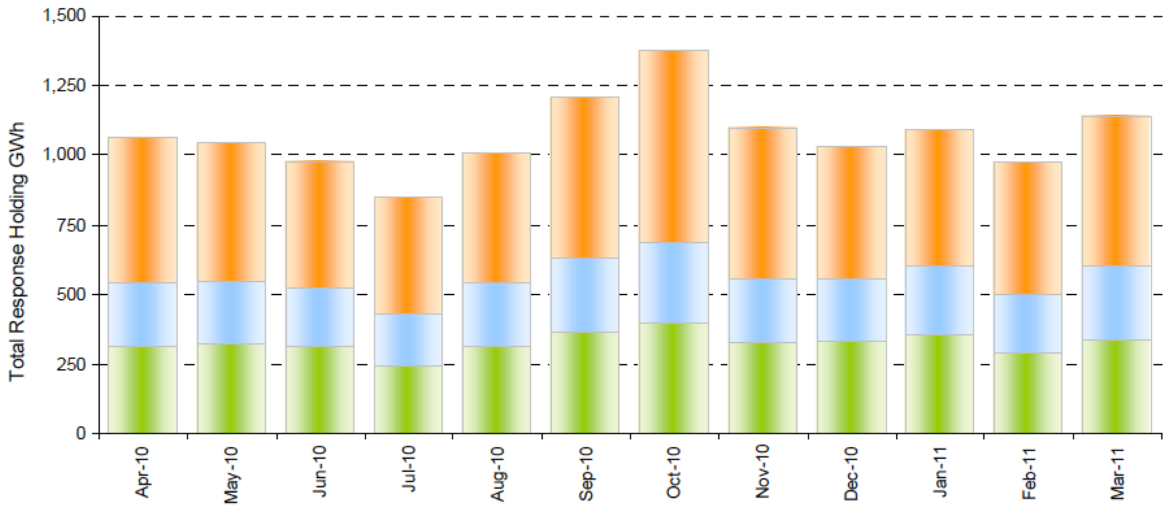

Figure 5: Frequency holding payment in 2010/11 (source NG Procurement guidelines report)

Response Energy Payment (£/MWh): Remunerates via Balancing Mechanism the amount of energy delivered to and from the system when providing Frequency Response. Details of response energy spend in 2010/11 are shown in Figure 5

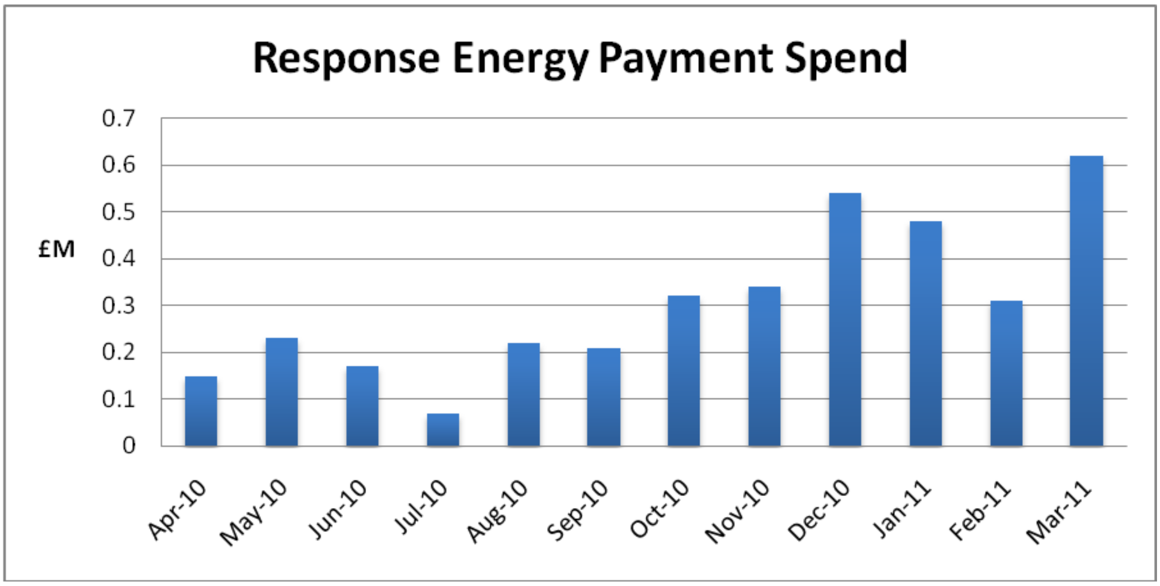

Figure 6: NG Response energy spend (source: NG Procurement guidelines report)

Firm Frequency response (FFR) – This service represents firm provision of Dynamic or Non-Dynamic Response to changes in the system frequency. This service can be provided by a BMU including existing Mandatory Response Providers, and non-BMU providers of demand and generation. The FFR service provides a route to the response market for the providers whose services could be inaccessible and therefore improves market liquidity.

Frequency Control by Demand Management (FCDM) – Represents frequency response through interruption of demand customers. The electricity demand is automatically disconnected in cases where the frequency falls below a preset value and is activated by a low frequency relay. The interruption will last 30 minutes and statistically, interruptions are likely to occur between 10 and 30 times per annum. In order to participate in the FCDM scheme the provider needs to satisfy a number of technical requirements. This service is provided through bilateral negotiations between NG and providers. Once all of the terms are agreed, the provider must declare availability on a weekly basis. Payment is structured so that an Availability Fee (£/MW/h) is paid against metered demand in the Settlement Period where NG has accepted site Availability in advance. FCDM as a system service falls under collection of services known as the Commercial Frequency Response. Typical volumes and prices for FCDM service is not available as NG publishes only figures for the Commercial Frequency Response and not for the individual services.

2.2.2 Reactive Power

Power flows must be carefully controlled in order to operate the system within acceptable voltage limits to meet the Transmission Licence requirements. Reactive power flows can lead to significant changes in voltage across the system, meaning that reactive power balance between sources of generation and points of connected demand needs to be monitored and maintained. The following methods are used by National Grid to control Reactive Power:

Obligatory Reactive Power Service (ORPS) – is provided by varying reactive power output. All BMUs must be capable of supplying their rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the BMU terminals. Also the short circuit ratio of the BMU must not be less than 0.5. The reactive power output under steady state conditions should be fully available within the voltage range +/-5% at 400kV, 275kV, 132kV and lower voltages and must have a continuously acting automatic excitation control system to provide constant terminal voltage control of the BM Unit without instability over the entire operating range of the BM Unit. The full requirements for the ORPS are contained in Grid Code CC6.3.2.

This service can be procured either via Market Arrangements or via Default Payment arrangements. The reactive power tender process is held every six months for participating generators.

Enhanced Reactive Power Services (ERPS) – Is the provision of the reactive power output which exceeds the minimum technical requirement of ORPS or reactive power capability from any other plant which can generate or absorb reactive power but it is not required to provide the ORPS. This service is designed to provide access to the reactive power market and for new reactive capacity made available. Similar to the ORPS, the ERPS is procured via tenders.

2.2.3 Reserve Capacity Service

Reserve Capacity in the form of either generation or demand reduction is required in order to successfully manage unforeseen demand increase and/or generation unavailability. Different synchronised and non-synchronised sources require different service delivery lead-times. The following services are used by National Grid to maintain Reserve Capacity requirements:

Fast Reserve - Represents the rapid and reliable delivery of active power provided as an increased output from generation or a reduction in consumption from demand sources. Active power delivery must start within 2 minutes of the despatch instruction at a delivery rate in excess of 25MW/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. The Fast Reserve Contracting Process has three key stages:

> <u>Pre-qualification:</u> Potential providers are required to fill in a questionnaire detailing their plant capabilities. Success in meeting all of the pre-prescribed criteria allows a

provider to enter into a framework agreement and offer either an Optional and/or a Firm service to NG.

- Optional Service: Upon successful pre-qualification, a framework agreement is entered into which puts no obligation on either party but allows optional despatch of Fast Reserve when available. Payments are subject to a specific system services Agreement. The provider receives (post despatch) an Enhanced Rate Availability Fee (£/h) when fast reserve despatch services are provided to National Grid. The Enhanced Rate Availability Fee is defined by the provider in the framework.

- Firm Service: Providers of the Firm Service will receive an Availability Fee (£/h) for each hour in a Tendered Service Period where the service is available. National Grid will notify 'windows' during which it requires the service to be provided, for which a Window Initiation Payment will be made. During a window, providers may also specify a Positional Fee (the cost of putting plant in a position where fast reserve may be provided). All fees for the Firm Service are submitted by the provider as part of the tender.

Fast Start - This requires the provider to have a suitable generating plant, usually Open Cycle Gas Turbine (OCGT), to start rapidly from a standstill condition and to deliver its rated power output, automatically within five minutes following initiation of a Low Frequency (LF) relay, or within seven minutes of a manual instruction via an Electronic Data Log from National Grid. This service is designed to reduce the risk of further system frequency reduction following an abnormal loss or exceptional mismatch between generation and demand. Fast Start is procured through bilateral contracts. However these requirements can be met via other reserve services.

Short Term Operating Reserve (STOR) – This is the provision of extra power in the form of either generation or demand reduction during periods when actual demand is greater than forecast demand and at times when plant breakdowns need to be covered. The minimum capacity is 3MW, delivered no later than 240 minutes after instruction and should be delivered for at least 2 hours. There are two forms of the STOR service; Committed and Flexible. Committed service providers offer service availability in all of the required availability windows in each season, and upon accepting the tender, National Grid commits to buy all services offered. Flexible service providers are not obliged to offer services in all availability windows and National Grid is not obliged to accept and buy all services offered. Only Non-BMU participants are able to tender for the Flexible service.

Negative Reserve – This is also known as downward regulation or footroom. Negative reserve provides the capability to reduce the amount of generation output on the system in order to ensure that the frequency can be kept within its statutory limits and does not rise out of control due to an excess of generation. It is necessary to control the level of negative reserve held on the system to ensure that the frequency can be kept within its statutory limits. High levels of wind turbine and nuclear output during periods of low demand generally results in other more flexible generation reducing output and moving towards their minimum stable output, leaving little ability for National Grid to further reduce generation output. National Grid manages these issues at present via forward trading on a BMU specific basis, actions in the Balancing Mechanism and the recently developed Generation Curtailment Service (GCS) contract.

The Generation Curtailment Service (GCS) - Is a service for the provision of the reduction in generation output, specifically from sites that do not participate in the Balancing Mechanism. At present the Generation Curtailment requirement (and the development of GCS services) is focused on generation in Scotland and is foreseen as a rare event (0 up to 5 times per year). The service will provide the ability to curtail a specified volume of generation in return for a fee. However, in extreme cases, there could be an insufficient volume available to reduce the level of unresponsive generation. In these circumstances, National Grid issues Negative Reserve Active Power Margin (NRAPM) warnings to the market to signal the shortage of responsive plant and request additional plant flexibility. If the NRAPM warnings have no effect, as a last resort National Grid could instruct plant to desynchronise under these NRAPM conditions in accordance with Grid Code section BC2.9.4. The Generation Curtailment Payment is calculated as follows:

GCS Payment = Generation Reduction x Utilisation Price

Utilisation Price (£/MWh) is agreed on a bilateral basis and detailed in the Bi-lateral Agreement. It is only paid when the service is utilised and energy is delivered.

There are currently no current contracts for provision of this service.

Footrom is usually made freely available by fully loaded units, or over periods of low demand needs to be created by desynchronising units operating at stable export level (SEL) and replacing the lost energy by increasing the loading on other units above SEL.

The Balancing Mechanism(BM) Start-up Service (Warming) – This service gives National Grid 'on-the-day' access to additional generating units that would not otherwise have run, and could not be made available in BM timescales due to either their technical or commercial characteristics. BM start up costs relate to the actions that the SO has to take to ensure that balancing mechanism units (BMU) are ready for use within BM timescales; this includes the process of BMUs “warming up”, during which the BMU is being prepared to generate if and when an offer is issued by National Grid. Once a BMU has reached critical operating temperatures, additional fees may be incurred to hold the unit at readiness to synchronise – this is known as “hot standby”.

2.2.4 System Security

National Grid has the obligation under GB Security and Quality of Supply Standards GB SQSS) of ensuring the security and quality of electricity supply across the GB Transmission System. There are a variety of tools available to assist National Grid in achieving this, including the following:

Transmission Constraint Agreement - A transmission constraint arises where the system is unable to transmit the power due to congestion at one or more parts of the transmission network. National Grid is responsible for ensuring the system remains within safe operating limits and that the pattern of generation and demand is consistent with any system transmission related constraints (for example due to a planned outage of a circuit). Whilst National Grid will endeavour to place outages coincident with relevant generation outages in order to minimise constraint costs it may be necessary to take actions (by entering into a Transmission Constraint Agreement, trading or taking actions in the Balancing Mechanism with generators, suppliers and large customers) to resolve constraints on the transmission system.

Intertrip – Intertrip services are required as an automatic control arrangement where generation or demand may be reduced or disconnected following a specific event to relieve localised transmission network flows, system instability and / or system voltages. There are two types of intertrip services:

- Commercial Intertrips - may be specified at the time of entering into / negotiating a Connection Agreement;
- System to Generator Operational Intertrips- specified at the time of entering into a Connection Agreement.

Automatic intertrip operation generally requires the monitoring of a number of transmission circuits (in a zone) which are linked with system protection arrangements. If a circuit which is selected by an intertrip scheme trips, the logic process will then trigger activation of the scheme to disconnect generation or demand. Intertrips may be required as a condition of connection, and some Intertrips may also be used to manage transmission constraints.

Maximum Generation Service - The Maximum Generation Service (MGS) is required to provide additional short term generation output during periods of system stress for system balancing. This service allows access to available unused capacity outside of the Generator’s normal operating range. MGS will be initiated in specific circumstances by the issuing of an Emergency Instruction in accordance with the Grid Code BC2.9.2.

Black Start – Black Start is the term given to the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again. To provide this service power stations require auxiliary plant to enable the main generating plant to start up independently from off-site power supplies. Only a limited amount of Black Start is required with around a 1/3rd of large plant having this capability. This service is procured from generators of over 200MW and the auxiliary plant has to meet a number of specific pre-set technical conditions. Regular inspection and testing of all the associated station plant on both the main and auxiliary generating units is required. Testing is carried out in accordance with the Grid Code and the specific Commercial Services Agreement. The likelihood of a total or partial system shut-down occurring is considered remote and the service will only ever be called upon under extreme system outage conditions.

Emergency Assistance - Emergency assistance, also referred to as a SO-to-SO service, is a specific interconnector service where additional active power support is provided by one electrical grid system to another to cover off extreme unforeseen system circumstances. This system to system service can result in one or both grid systems being operated beyond their normal security standards. The service is therefore required as a measure of last resort and historically, its use has been extremely rare.

2.2.5 Procurement of Services

National Grid procures Balancing Services in accordance with Condition C16 of the Transmission Licence. This framework obliges National Grid to "operate the transmission system in an efficient, economic and co-ordinated manner". It also requires a number of statements and reports on the procurement and use of Balancing Services to be established.

The Procurement Guidelines is one of the required Balancing Services statements, and sets out the principles used in the procurement of Balancing Services, the kinds of Balancing Services that National Grid may be interested in purchasing and the mechanisms by which it conducts the procurement process. The Procurement Guidelines are published on the National Grid Industry Information website and are subject to annual review and industry consultation.

Where there is, or is likely to be, sufficient competition in the provision of a Balancing Services, National Grid seeks to procure that service via an appropriate competitive process or market mechanism. This will include providing potential participants with an Invitation to Tender (ITT) with a statement of service requirements, terms and conditions, governance, principles and criteria for evaluation and information on previous tenders. The timescales for these competitions vary according to the service sought.

For the purpose of this report procured services are split into 3 main categories:

1. Services procured via Market Arrangements;
2. Services procured via Non-Tendered Bilateral Contracts; and

3. Constraints services

2.2.5.1 Services Procured via Market Arrangements

Services procured through regular market tendering arrangements are:

> **Reactive Power** - Tenders are held every six months. NG assesses the tenders in accordance with the criteria specified in the Connection and Use of System Code (CUSC)and a successful tender then becomes contractually binding. If the tender is not successful the BMUs will be paid on Default Arrangements if they provide the service as instructed, Market arrangements allows the generator to request an Available Capacity Price (£/MVar/h) and/or a Synchronised Capability Price (£/MVar/h) and/or a Utilisation Price (£/MVarh). In the absence of the market agreement a Default arrangement payment (£/MVarh) is made to BMUs for utilisation. It is calculated on a monthly basis with reference to both RPI and Over the Counter (OTC) base load power indices. If the tender is not successful the BMUs will be paid on Default Arrangements if they provide the service as instructed.

> **Fast Reserve** - Is procured via a monthly process and requires pre-qualification to establish a framework agreement prior to tendering. Potential providers are required to fill in a questionnaire about their plant capabilities. Success in meeting all of the pre-described criteria allows a provider to enter into a framework agreement and offer either an Optional and/or a Firm service to NG. Providers of the Optional Service will receive an Enhanced Rate Availability Fee (£/h) payment for the provision (following despatch) of enhanced MW run-up and run-down rates. The Enhanced Rate Availability Fee is defined by the provider in the framework agreement. Providers of the Firm Service receive an Availability Fee (£/h) for each hour in a Tendered Service Period when the service has been made available. In this regard National Grid notifies 'windows' during which it requires the service to be provided and for which a Window Initiation Payment is be made. During a window, Providers may also specify a Positional Fee (the cost of putting plant in a position where fast reserve may be provided). All fees for the Firm Service are submitted by the provider as part of the tender. A utilisation fee (£/MW/h) is payable for the energy delivered in both categories of service (for BMU participants via a bid/offer acceptance). For the firm service this utilisation fee will be capped by the tender parameter submitted.

> **Short Term Operating Reserve** (STOR) - In order to tender availability under this contract all providers require a Framework Agreement in place. STOR is procured via competitive tender with three tender rounds per year. All the interested parties have to fulfil the pre-qualification by signing onto the framework agreement before participating in the tender. STOR Services have two payment elements: Availability Payment (£/MW/h) and Utilisation Payments (£/MWh).

> **Tendered Firm Frequency Response** (FFR) - This service is procured through a monthly tender process but in order to participate in the tender process the FFR provider needs to pass a pre-qualification assessment and sign a framework agreement. Having considered the quality, quantity and the nature of the services, National Grid accepts the most economical tender. A successful tender then becomes contractually binding, National Grid notifies providers of window nominations in advance and, if the provider allows, this payment is payable if National Grid subsequently revises this nomination. FFR has a four-part payment structure. However, it is not compulsory for providers to tender for all elements of the service. Figure 7 below represents an illustrative example of Dynamic FFR provision.

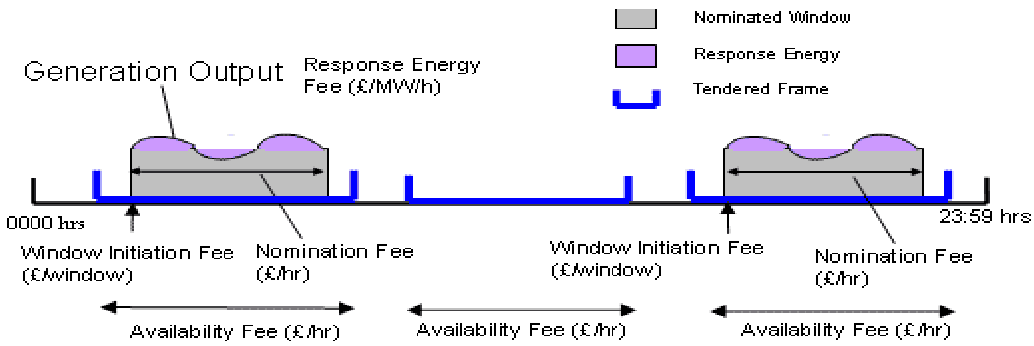

Figure 7: Illustrative Dynamic Firm Frequency response Provision (source: NG)

Availability Fee (£/hr) – for the hours for which a provider has tendered to make the service available for Tendered Utilisation fees

Window Initiation Fee (£/window) – for each FFR nominated window that National Grid instructs within the Tendered Frames.

Nomination Fee (£/hr) – a holding fee for each hour utilised within FFR nominated windows.

Tendered Window Revision fee (£/hr) - National Grid notifies providers of window nominations in advance and, if the provider allows, this payment is payable if National Grid subsequently revises this nomination.

Response Energy Fee (£/MWh) – based upon the actual response energy provided in the nominated window.

Tendered FFR same as FCDM falls under collection of services known as the Commercial Frequency Response. Typical volumes and prices for Tendered FFR service is not available as NG publishes only figures for the Commercial Frequency Response and not for the individual services

2.2.5.2 Services Procured via Non-Tendered Bilateral Contracts

Where National Grid considers that there is insufficient competition in the provision of a Balancing Service (e.g. where there is some form of local monopoly) the contracted service is generally negotiated bilaterally. Services that are procured by these Non-Tendered Bilateral contracts are:

- **Mandatory Frequency Response** - After successful assessment by National Grid (generating unit meets the minimum requirements) a Mandatory Service Agreement is put in place, which allows National Grid to call in the Service when it is required. When the service provider delivers the service as instructed, they will be paid in accordance with the CUSC with two types of payment: A Holding Payment (£/h) and a Response Energy Payment (£/MWh).

- **Commercial Frequency Response** - Commercial Frequency Response is a collection of services that can be provided by demand side participants and generation plant. The technical characteristics of these services are different to those required under mandatory service arrangements, and range from enhanced mandatory dynamic services through to non-dynamic services affected via Low Frequency relays. Part of the contract portfolio includes services provided by demand side participants via the Frequency Control by Demand Management (FCDM) service and through Firm Frequency Response (FFR) tender rounds.

- **Fast Start** - This service is designed to reduce the risk of further system frequency reduction following an abnormal loss or exceptional mismatch between generation and demand. Fast Start is procured through bilateral contracts. However these requirements can be met via other reserve services. Fast Start Services have up to three payment elements which are self explanatory: Availability Payment (£/h), Start Up Payment (£/start), Automatic Delivery Payment (£/min which are all recovered through Balancing Mechanism charges.

- **Black Start** - Black Start providers are paid an agreed fee per settlement period for their availability and a utilisation payment both for testing purposes and in the event of a Black Start. The payments will depend on a number of factors including what plant has been instructed, whether all the plant is registered as a BMU and what type of fuel was required. In a Black Start situation, payments for the energy provided are dealt with under the BSC.

- **Fast reserve (Non-Tendered)** - Non-Tendered Fast Reserve is a service that is contracted on a bilateral basis with service providers. The nature of the service is similar to the Firm Fast Reserve service although the payment and utilisation mechanisms differ for each service.

- **Intertripping** - Intertrips may be required as a condition of connection (System to Generator Operational Intertrips) and some intertrips may also be used to manage transmission constraints (Commercial Intertrips). Payments for System to Generator Operational Intertripping schemes are administered via The Connection and Use of System Code (CUSC). Two levels of payment are made for intertrip actions: Capability Payment (£/Settlement Period) and Intertrip Payment (£/Generating Unit/Trip).

- **SO-to-SO services**- This service is provided mutually with other System operators connected to the GB System via interconnectors. The inter-connector agreements set out the commercial arrangements and operational circumstances under which the flow on the inter-connector can be managed post interconnector gate closure. The SO to SO service covers two balancing services, Constraint Management and Balancing (CMB) and Emergency Assistance.

- **Maximum Generation Services** - The service is provided on a non-firm basis with providers being paid for any energy that they deliver. The arrangements for MGS are contained within the CUSC. This service is rarely used with last utilisation in July 2006.

2.2.5.3 Constraints

A transmission constraint represents the network inability to transfer any additional power due to congestion at one or more part of the transmission network and it is caused by generation/demand and/or outages. In the event that the system is unable to accommodate power flow in the way required, National Grid will take actions in the market to increase and decrease the amount of power at different locations on the network.

It is National Grid's responsibility to operate the transmission network within safe operating limits and ensure the pattern of generation and demand is consistent with any system transmission related constraints (for example due to a planned outage of a circuit). To minimise constraint costs, network outages are planned whenever possible so that outage actions coincide with corresponding generation outages. Where planned measures of this kind are not possible it may be necessary to take more spontaneous action (by entering into a Transmission Constraint Agreement, trading or taking actions in the Balancing Mechanism with generators, suppliers and large customers) to resolve constraints on the transmission system.

The exact way in which a constraint is managed depends on a number of factors including network conditions, the nature of power flows on the network, the duration of the requirement, local and national generation output mix and the local level of system demand. Therefore the technical requirements will be specific to the location of the constraint and defined in the Commercial Services Agreement. Where sufficient competition exists, National Grid will seek to contract via some form of market mechanism. In other circumstances, bilateral contracts will be entered into with the service providers.

In the event of an active transmission constraint, when National Grid identifies specific BMUs that could be utilised to resolve the constraint, it takes the necessary action on these units and they are subsequently 'SO-flagged' by the National Grid Control Room in real time for the duration of the constraint resolution. The rationale behind this is that the corresponding output data from the BMUs can then be remove from the bid/offer acceptance (BOAs) stack for the duration of time taken to resolve the transmission constraint.

The total constraint cost depends on a number of factors and it has a value in excess of £160 million. Balance between contracted volumes and remaining balancing mechanism actions to manage constraints is influenced by National Grid's assessment. Figure 8 represent National Grid's constraint cost split during 2010/11 and represents the latest available figures.

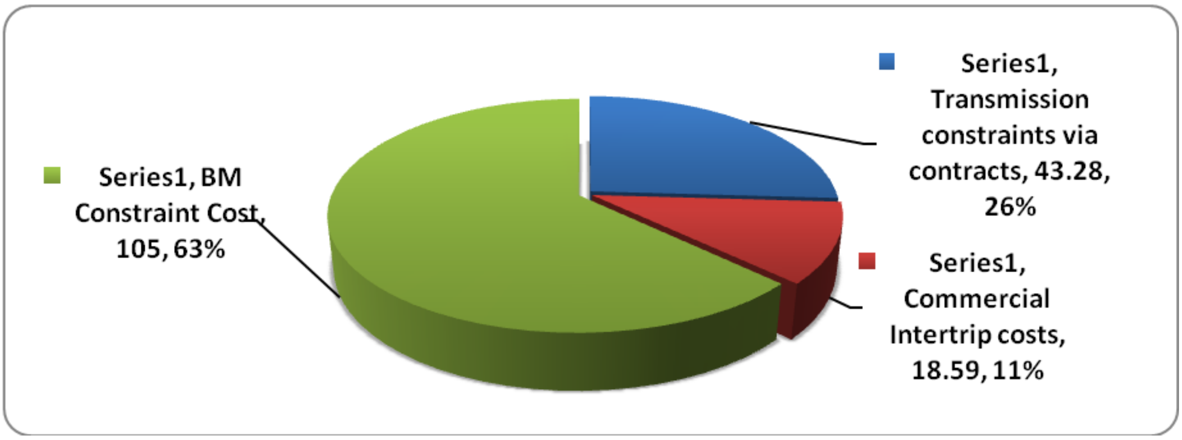

Figure 8: Total Constraint cost in £ millions (source: NG Procurement Guidelines report)

2.2.5.4 Cost of the system services

The total cost of the system services provided depends on a number of factors and varies every year. Figure 9 shows the split of the different services procured by National Grid during 2010/11.

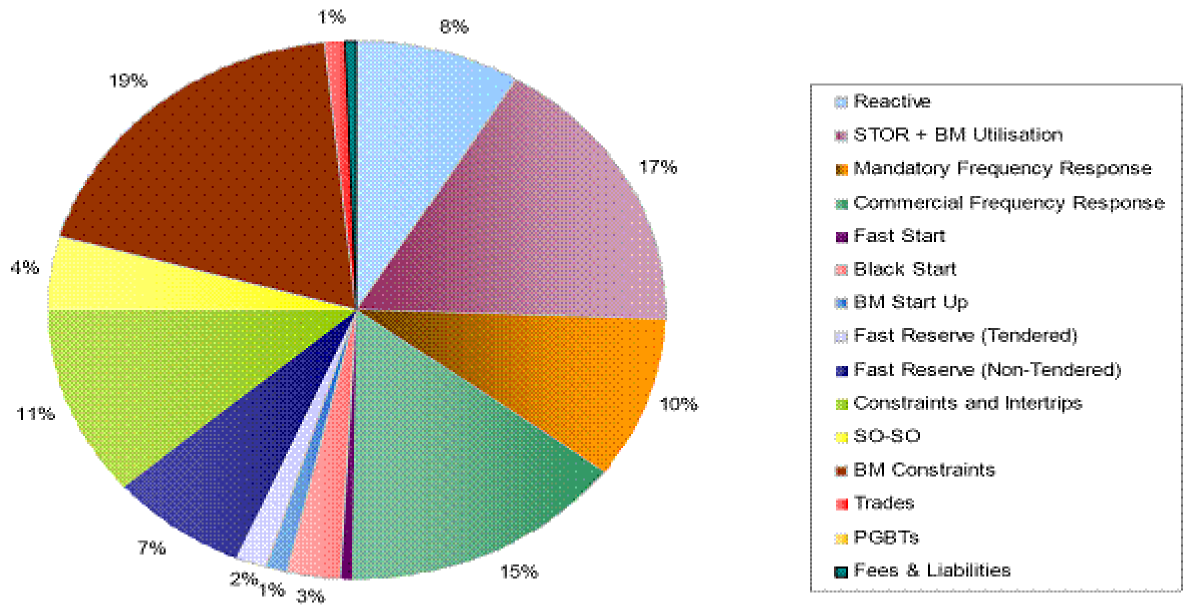

Figure 9: Split of Balancing Services Costs 2010/2011 (source: NG Procurement Guidelines)

It is interesting to break this cost allocation into mandatory, necessary and commercial services.

- Mandatory services consisting of mandatory frequency response and reactive power make up 18.5% of the total cost.
- Necessary services consist of Black Start and Fast Start and these make up 3.5% of the cost and are agreed under bilateral contracts.
- Almost 78% of the costs are for Commercial Services that assist National Grid in meeting its licence obligation and which will be negotiated between the participants and National Grid either through a market competition, the balancing mechanism or a bilateral negotiation.

The outturn costs of the services (market revenues delivered for AS) procured by National Grid are provided in the Procurement Guidelines and the costs for 2010/11 (which underpin Figure 9 above) are shown in detail in the table below with other associate summary statistics. These comprise a total of ~£547m which is equivalent of 1.9%[2] of the total sales in the electricity market in the UK.

[2] This is based on £29,823M(source DUKES-DECC) of total electricity sales in the UK, reduced by NI sales figure estimate.

Table 3: Costs of system services from Procurement Guidelines Report

Balancing Services	Info Provision	Total Cost £m
Reactive Power market	Utilisation Volume (Market)	0
	Utilisation Volume (Default)	19855 GVArh
	Total Spend (Market)	0
	Total Spend (Default)	47.41
STOR	Annual Average Availability Payments	
	Average Contracted Utilisation Payments	
Including BM and NBM Availability & Utilisation	Total Spend in £m	96.38
Mandatory Frequency Response	Holding Volumes & Prices:	Primary / Sec /High
	Average Volume held MW	446 321 703
P = Primary	Average price £/MW/h	3.11 1.72 5.57
S = Secondary	Total Holding Spend	49.92
H = High	Total Response Energy Payment Spend	3.67
Commercial Frequency Response	Total Spend	83.78
Fast Start	Total Spend	3.69
Black Start	Total Spend	15.28
BM Start Up	Total Cost of BM Start Up	5.73
Fast Reserve-Tendered	Total Spend on Availability & Utilisation	9.8
Fast Reserve Non-Tendered	Total Spend on Availability	40.26
SO to SO	Total Spend	25.02
System to Generator operational inter-trips	Capability Payments	0.57
	Utilisation Payments	0
Commercial Intertrip Service	Total Spend	20.37
Ancillary Constraint Contracts	Total Spend	43.28
Maximum Generation Service	Total Spend	0
All Other Services	Total Spend	3.12
BM Constraints	Total Spend	105.12
Forward trading	Net Cost	-6.2
PGBT	Total Cost	-0.19
	TOTAL £m	547.01

The price for commercial services will be a matter of negotiation between National Grid and the provider or will be subject to market competition. There is no requirement for these to relate to the costs of service provision. For many of the services there is some discretion in the exact technical service that the provider offers and therefore the price cannot be simply set for a particular service as technical parameters will vary. This approach is believed to give National Grid the maximum freedom in purchasing the services required (along with their incentive arrangements) and in so doing, allow NG to minimise the overall cost of the services procured.

2.2.6 Incentives for Providers and the GBSO

2.2.6.1 The requirement to provide system services

Licensed generators have a requirement to sign and comply with the Grid Code. This code specifies that Reactive Power and Frequency Response need to be provided as mandatory system services. Failure to provide these services would place the generator in breach of the Grid Code.

Some generators are also required to provide Black Start and/or Fast Start services. The additional requirements for these services depend on the actual and expected provision of such services by existing providers. Each provider of necessary and commercial balancing services will have a bilateral Commercial Services Agreement (CSA) with National Grid which contains the provision for service provision (e.g. Black Start) and the commercial arrangements that prevail between the parties from time to time. The CSA will define the service that is required (and when) and detail the consequential payments that will be made for each balancing service provided. Some generators will be required to provide System to Generator Operational Intertripping Schemes as a condition of connection.

2.2.6.2 Incentivising Service Provision

Whilst there are some necessary and mandatory services, the majority are provided by participants on a commercial basis as revenue generating opportunities alongside business as usual production. In all cases NG encourages the best terms for delivery, effectively creating a competitive operating environment for the provision of AS.

Both technical performance and commercial terms for the provision of a particular service can vary between different users. The provider will therefore be assessed on the relative merits of different offers over a range of factors, not just price. In this regard NG has a certain amount of flexibility when making contracts as it can construct different portfolios of individual services from a range of providers to achieve the same overall AS objective. This freedom of contracting over a range of options provides an incentivised framework for the specific services sought and spreads delivery risk over a range of service provider participants.

There is no clear indication how AS performance against expected service provision is monitored.

2.2.6.3 Incentivising the GBSO

In order to encourage the System Operator to be innovative in looking at ways to reduce costs, each year Ofgem develops System Operator incentive schemes. This approach is designed to encourage National Grid Electricity Transmission (NGET) to operate the electricity system in an efficient and economic manner, and to effectively manage the costs of operating each system.

The incentive scheme is produced through extensive consultation with the SO and other industry parties, in order to develop a fair and efficient set of incentives. The SO incentive schemes establish cost targets that National Grid is expected to achieve in performing its SO roles. If actual costs are below the relevant target, National Grid is permitted to receive an incentive payment, and similarly if actual costs exceed the target, it faces an incentive penalty.

The size of this payment or penalty is determined by the relevant sharing factors that are agreed as part of the overall incentive schemes. The sharing factors are in place to strike a fair balance between the risks and rewards faced by the SO and customers. The maximum payment the SO can receive under the incentive scheme framework is subject to an upper cap, and similarly the maximum penalty it can be liable for is bounded by a lower collar.

2.2.7 Cost Recovery

As indicated above, the total GBSO procurement cost in 2010/11 was ~£397m. Whilst system services form one major component of the overall costs of balancing the system, there are other costs which National Grid incurs, including (most obviously) the cost of administration (accepting bids and offers) in the Balancing Mechanism. In 2010/11 the total costs of balancing services, including associated GBSO incentive scheme payments was ~£547m. This figure does not include the acceptance of Bids and Offers (BOA) in the Balancing Mechanism but includes BOAs for constraint management and BM STOR utilisation.

National Grid recovers the total costs of balancing the system though Balancing Services Use of System (BSUoS) charges. The Statement of the Use of System Charging Methodology, available on National Grid’s website, includes a detailed methodology for the calculation of daily BSUoS charges, some worked example and information on BSUoS charge settlement.

The Balancing Services Use of System charge comprises:

- Internal elements – These are the internal SO costs such as staff, buildings, (operational expenditure) , IT etc incurred in performing the GBSO role;
- External elements – All costs relating to the services used by the GBSO to balance and secure the system i.e. system services contracts and utilisation, plus Balancing Mechanism actions (and related energy trades); and
- Incentive payments/receipts – Based on the GBSO Incentive scheme typically agreed with Ofgem each year. These can be positive or negative depending on whether the GBSO is outperforming or underperforming against the annual cost target set.

See Figure 10 below for an illustrated breakdown:

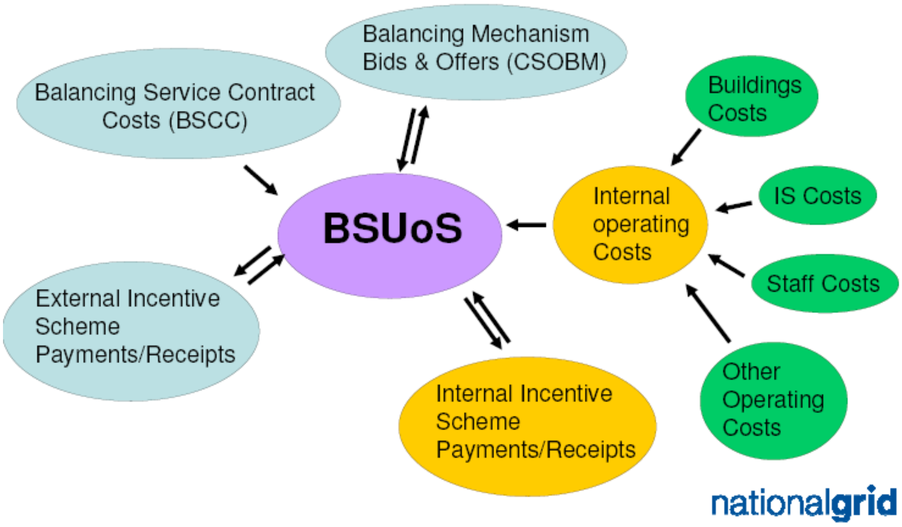

Figure 10: Breakdown of BSUoS (source: National Grid Operational Forum Jan 2007)

The BSUoS charge is paid for by users (i.e. generators and suppliers) of the transmission system in each Settlement Period. The charges are calculated, ex-post, on a half hourly basis and the lead BSC party of the BMU is billed on actual outturn. The BSUoS charges are not based on fixed prices, they serve to recover the specific costs of balancing. Each user is charged a proportion of the recoverable costs based on their metered usage relative to total use of the system.

The charges include the cost of providing ancillary services (denoted above as Balancing Services Contract Costs) and other large costs such as those associated with the provision of Balancing Mechanism arrangements[3]. BSUoS charges therefore vary significantly for each half hour settlement period and are not fully known until final reconciliation. The average time weighted cost for the year from 1 April 2010 to 31 March 2011 was £1.11/MWh. However within this, there are dramatic variations as BSUoS is levied on each half hourly settlement period. For example, for 2010/11 half hourly BSUoS prices varied between a maximum of £6.81MWh in one half hourly settlement period to a minimum of -£0.82MWh.

2.2.8 Evolution of Services

The standard system services such as Frequency Response and Reactive Power as found in all electricity markets worldwide have been in place since pre-privatisation.

Following privatisation of the GB industry in 1990 there was some limited development of commercial service provision but essentially most of the service arrangements that existed at the time rolled over into the new Pooling arrangements which other than adopting price

[3] Balancing Mechanism outturn costs can be positive or negative

based principles was little different in structure to the original public centralised despatch approach.

During the early 1990's there was little further development. However, the implementation of the first SO Incentive Scheme in 1994/95 motivated National Grid to seek to develop some competition in provision of the existing services and to explore new options and opportunities.

It was the implementation of NETA in 2001 which provided the main trigger for the first major development of services Due to the radically different structure of the market. In particular the concepts of self despatch up to a short notice gate closure saw National Grid develop new service options such as 'warming' and 'hot standby' (this service ensured that flexible oil plant which were expensive and might otherwise be unavailable, were available to assist balancing in real time).

The implementation of NETA also saw the start of strong regulatory pressure to introduce more market based approaches to the provision of system services with the incorporation of guidelines for compliance with the new Balancing regime and Procurement Guidelines; where the guiding philosophy was based on the principle that the adoption of a market approach to procurement (and associated market information transparency) would lead to price discovery and thus competition and thus reduced costs.

Since 2001, there has been substantial development in the services procured by National Grid as Ofgem have encouraged more market and/or tender based approaches to procurement and an increase in information transparency between participating parties. This market based approach has driven the existence of development groups such as the Balancing Services Standing Group and communication/consultation forums such as National Grid's Operational Forum.

Post NETA services began to be procured through the developing market but the vast majority were still procured on an annual basis. In 2003 wholesale price collapse along with the market exit of a number of established players caused many generators to review their position in relation to legacy plant portfolios and in, certain cases, mothball units that were no longer suited to the evolving operating framework. Consequently National Grid found itself potentially short of generation for reserve holdings and thus introduced new services within the year (Supplementary Standing Reserve) to ensure sufficient reserve was contracted. This is symptomatic of development in the last five years of more regular tender process for different system services, to the point that many are now procured on a monthly basis.

When BETTA went live in 2005, prevailing system services were simply expanded to cover the entire GB region rather than England & Wales alone. Thus whilst this placed more emphasis on certain system operation issues (e.g. constraints) and associated service provision, it did not lead to any particular new service offerings from National Grid.

Since 2004 there has been continuing evolution of ancillary service provision, for example, Frequency Response being moved from cost based remuneration to price based remuneration. As National Grid has faced rising procurement costs it has been strengthening its endeavours to encourage wider participation (and thus competition) for system service provision, from other peripheral players such as smaller generators and demand side participants.

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

National Grid has been actively promoting demand side participation in balancing services over recent years and has been successful in the integration of demand side service provision in services such as Short-Term Operating Reserve (STOR) and Frequency Response. In addition to demand side, smaller generation capacities are also encouraged into balancing services markets via an aggregation model. This allows a number of smaller loads (which alone may be too small to participate in balancing services where typically the minimum requirement is 3MW) to be aggregated from a number of sites. This model works particularly well in the STOR service where a number of aggregating companies actively participate.

An integrated single year Balancing Services Incentive Scheme (BSIS) scheme to incentivise National Grid to operate sufficiently has been in place since the introduction of the NETA in 2001 and Ofgem has been promoting a move to multi-year schemes since 2009 with a view that schemes of this kind will promote system operation efficiency and reduce regulatory burden. The main obstacle impeding an earlier move of this kind is known to be the difficulty experienced in establishing the potential impact of unpredictable and uncontrollable costs. These volatile parameters are modelled on an 'Ex-Post' basis with no agreed target prior to scheme start. Instead as the scheme progresses, out-turn (Ex-Post) data is used for those parameters that are difficult to forecast (fuel prices, wholesale electricity prices and Net Imbalance Volume (NIV)) which is then combined with a dataset containing forecast (Ex-Ante) data for other model inputs and run through National Grid's models to give an Ex-Post target cost calculation for Incentivised Balancing Costs. The revised approach to incentives and a proposal to implement a two year incentive scheme placed significant reliance on the accuracy of the modelling techniques. The most important part of the new scheme is that no incentive balancing cost target is agreed prior to the start of the scheme, and it will only be published once all volatile external factors are known and entered into the model. See Figure 11 below.

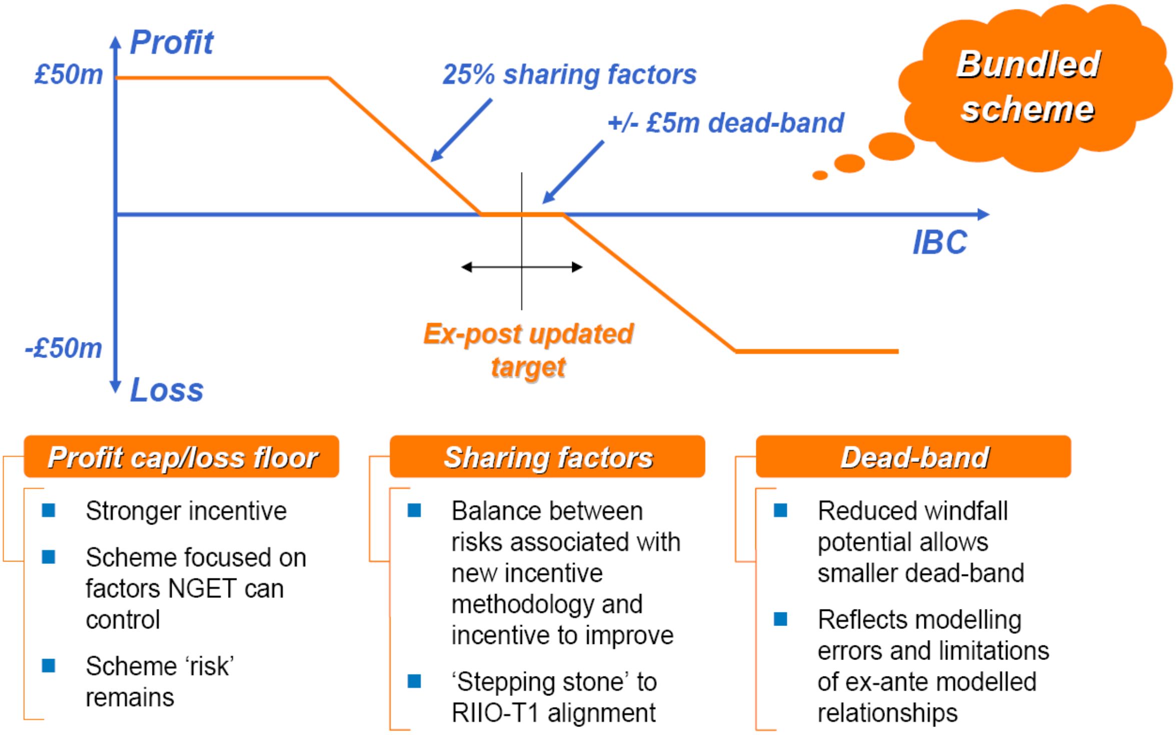

Figure 11: New BSIS Scheme (Source: NG Electricity Operational Forum 2011)

2.2.9 Future Developments

As indicated above, system services are ever evolving in a continuous effort to improve the efficiency and effectiveness of service provision. This process results in changes and modifications to wholesale market structures and rules, changes in the behaviour of participants and associated refinement to the GBSO requirements. Within this, National Grid (for its part) is keen to encourage the widest possible participation and thus competition in service provision; witness the SO Balancing Services Incentive Scheme, where as discussed above it can profit for efficient system operation. This is further reinforced by constant pressure from Ofgem on National Grid to continue to expand and improve its market mechanisms for the ongoing procurement of system services.

Thus at present there is an initiative on National Grid to improve information transparency regarding all aspects of service delivery to encourage greater participation. There is also a specific initiative aimed at encouraging more demand side participation. It is hoped that this will lead to the wider development of demand side services that can be more readily accommodated by a broader selection of services providers who may otherwise never engage in the process.

Drawing similarities with the All Island market (where wind generation is expected to form a growing share of generation capacity going forward) National Grid has already indicated that the growth of wind generation in GB will provide new operational challenges. Whilst this may principally lead to greater volume requirements for existing defined system services, it may also lead to the development of new services in the next 5-10 years specifically targeted at addressing the impact of wind volatility on the delivery cycle.

It is recognised that with predicted increase in connected wind power capacity, the damping effect or system inertia that conventional generators provide will reduce. However, wind turbines connecting to the system should be capable of providing synthetic inertia, so it is assumed that the overall system inertia will be comparable with today's values.[4]

Since June 2008, as part of the Electricity Networks Strategy Group (ENSG), Ofgem, Government, National Grid and number of other energy companies have worked together to produce a vision of the network requirements that will need to be met if the 2020 renewable energy target is to be achieved in full. In June 2009, National Grid published 'Operating the Electricity Transmission Networks in 2020' which is a representation of an initial consultation on a range of network issues and associated operating challenges that the industry is likely to face in 2020, directly resulting from significant changes in the overall GB generation mix. The analysis and its subsequent update in 2011 highlighted the impact of the changes in the electricity industry on requirements for Balancing Services. The increase in variable renewable generation (predominantly wind) creates a greater envelope of uncertainty across all timescales. National Grid's prediction shows that the overall forecast for managing the variability in wind output is around £286 million by 2020, with the forecast for procuring the full operating reserve requirement forecast to be between £565 million and £945 million.

Furthermore as the role of interconnectors in helping to balance and support the GB system has grown over recent years, with both RTE and SONI providing National Grid with "emergency" balancing services. With the increasing level of wind penetration it is expected that the use of over 3GW of interconnector capacity in system services provision will increase significantly e.g. providing increased level of negative reserve margins. In the longer term the aim is to enable full cross border system services provision (via the interconnectors) by generators themselves without either SO acting as an effective aggregator/agent on their behalf.

Potential new System Service Provision includes: Short term Operating Reserve (STOR), Fast Reserve, Firm Frequency Response and Frequency Control by demand management. Additionally, smart metering (and smart grid) development and rollout together with an increase in demand side resources will significantly increase demand side opportunities helping to augment the current array of system services options. Increased demand side

[4] NG publication: Operating the Electricity Transmission Networks in 2020 (published in Jun 2011)

availability to provide these services should have a significant impact on system services costs and could lead to an eventual reduction in the allied cost of Balancing Services.

2.3 Summary and Implications

Historically system services in GB were always addressed separately through a variety of market based bilateral arrangements. This continued after industry privatisation in 1990 and was not altered with the implementation of NETA in 2001 and BETA in 2005. Whilst there are some overlaps (provision services via BM instruction) this separation has largely been maintained.

The scale and maturity of the GB market means that the Regulator is very interested in the cost of system services necessary to maintain a reliable and efficient system, thus it is the only market in the study to have an overall SO incentive scheme. Within this National Grid has the freedom to develop, implement and operate services which it feels it needs to securely operate the system. This explains why system services in the GB market have seen more sequential evolution and ongoing refinement in the variety of services procured, than in any other market studied.

Another reason for the changing service provision is the high dynamism in the GB market structure (e.g. changing generation mix and location), and the impact that this has had on GBSO requirements. This can be witnessed by changes designed to encourage greater participation from a wider constituency of market participants (e.g. demand side) to meet the growing need for system services and at the same time contain delivery costs.

It is interesting to note that the implementation of new market measures does not necessarily mean lower costs de facto. The new pay-as-bid frequency market in GB, (previously a cost based market) has led to a very substantial increase in frequency response costs. Consequently, National Grid must seek to revise ongoing arrangements to mitigate/reduce these costs, and incentivise participants through the prevailing scheme (and schemes of its kind) to achieve acceptable levels of participation in relation to cost and performance. It is important to note, however, that the associated system services governance frameworks are such that the change process is generally quite complex and hence relatively slow to introduce.

One interesting feature from EirGrid's perspective is the GBSO's push to make greater use of the existing interconnections to improve short term service provision in an effort to combat increasing operational issues such as congestion.

In general the next decade is likely to bring added complications to energy markets as identified in the recent EMR White Paper. To date the main characteristics of the new proposals are:

1. Increasing demand (despite predictions of increased energy efficiency) as electricity replaces fossil fuels in both transport and industry;

2. Replacement of the existing generation infrastructure (flexible gas and coal-fired power stations responsive to demand changes) with a combination of inflexible, base load, nuclear and unpredictable, largely weather-based, renewable.

The complications are reflected in the need to establish a structure which will create enough space in the market for over 30GW of variable renewable generation (predominantly wind), whilst at the same time ensuring that there is enough flexible and responsive generation on the system.

The DECC anticipates adopting a number of measures to cover that capacity requirement. These include the use of:

> "Demand-side response"

> Local generation;

> Energy storage (although this option is very limited at present); and

> Interconnection with other grids that may have an excess of capacity at times when GB has a surfeit.

It is KEMA's view that a more complicated market coupled with changes in the generation mix will significantly impact the provision of system services. Additional flexible generation (or additional demand-side response) will be required to maintain existing quality of supply standards; and the Government still need to come up with a suitable policy that will practically incentivise entrance of significant new capacity. The White Paper has expressed a Government preference for a targeted mechanism in the form of Strategic Reserve (that pays only when utilised), rather than a market-wide mechanism (under which generators are compensated for providing capacity whether or not utilised) although both are being consulted upon. This new policy needs to provide adequate return on investment for System service providers even though they maybe rarely utilised. On the other hand if the returns are too lucrative then generators may intentionally reduce market capacity in order to participate in schemes that over compensate service delivery.

EirGrid could re-examine the GB market to see which structures may be appropriate for Ireland given a similar generation mix. However, the structure of the GB market is highly complex reflecting the size of the overall market and the levels of participation (production, wholesale energy and supply) supported. Generally the provision of AS has little relationship with the mainstream energy market (partly through market design), hence it tends to be supported on the margins. However, the increasing use of the interconnector(s) for system services could be of interest particularly as further interconnectors are built between GB, Ireland and other neighbouring European countries.

In summary, any lessons taken from the GB context for the application of system services in the Ireland context should carefully consider the relative scale of the GB market, the greater diversity of fuel mix and generation ownership. The negative GB experience from forcing the GBSO implementation of markets for those services where competition for provision is low or is monopolised by a dominant provider may also be useful when drawing up comparisons. However, there are positive GB experiences, for example:

> The way that system services have evolved in GB to meet suitable charging structures (e.g. generation mix);

> Market behaviour drivers following the introduction of NETA and BETTA; and

> The means by which the GBSO has sought to be innovative and encourage new system services providers to create greater competition.

3. New Zealand

3.1 Introduction and Market Overview

New Zealand is served by an isolated system made up of two islands, the North Island and South Island. Each has an HVAC transmission network and they are connected by an HVDC link. System maps provided in Section 3.1.4 of this report provide a detailed illustration of this.

Generation is located on both Islands; the South Island is mostly hydro while in the Northern Island there is a mix of hydro and thermal, conventional gas and coal fired plant, CCGT's and geothermal. South Island generally exports its hydro output to the North Island via the HVDC link, however during dry spells in the South, more thermal generation is despatched. In times of extreme water shortages the flow on the HVDC is from North to South in order to conserve water.

Until 1989 the Electricity Corporation of New Zealand (previously the New Zealand Electricity Department) was the country's sole generator and grid owner. Initially the transmission division was unbundled to form Transpower New Zealand and then in 1996 competition in the generation of electricity was introduced with the split of Contact Energy from state-owned generator. This was followed in 1999 by the further split of the remainder of ECNZ into three competing State-owned enterprises (SOEs): Meridian Energy, Genesis Power and Mighty River Power, and the privatisation of Contact Energy. The electricity market was self-regulating until 1 March 2004, when it began operating under the Electricity Governance Rules and the Electricity Governance Regulations, overseen by the Electricity Commission. A Ministerial Review in 2009 tightened the focus on market performance and, through the Electricity Industry Act 2010, provided for the electricity market to be governed by the Electricity Industry Participation Code (the 'Code'), overseen by the Electricity Authority, from 1 November 2010. The Act requires the Authority to address seven priority matters relating to:

- Payments to consumers and wholesale floor prices during shortages;
- Assisting retailers to manage risks created by transmission congestion;
- Facilitating active responses by large users to wholesale market conditions;
- Hedging market liquidity; and
- The Standardisation of distribution tariff structures and use-of-system rules.

The Authority's statutory objectives are to encourage and improve the competitive operating framework for electricity supply and generation, ensure reliable and sustainable supplies of electricity are continuously available and ensure the system is operated effectively and efficiently, across the whole of the sector, for the long-term benefit of New Zealand electricity consumers. The Authority maintains the industry Code and is responsible for ensuring participants comply with the prevailing Regulations and the Code.

The New Zealand market is a voluntary wholesale market with fully nodal design where retailers and large customers buy electricity directly from the spot market. The buying and selling of wholesale electricity is done via a "pool", where electricity generators offer electricity to the market and retailers bid to buy the electricity at prices set half-hourly. They will also enter into hedge contracts (CFD's) which will smooth out some or all of the spot price volatility. The spot and hedge markets are the major components of the wholesale electricity market in New Zealand, which also includes the instantaneous reserves market and the system services market. Trades take place at approximately 285 nodes across New Zealand every half-hour. Generators make offers to supply electricity at 59 grid injection points (GIPs) at power stations, while retailers and major users make bids to buy electricity at 226 grid exit points (GXPs) on the national grid. The highest-priced generator actually required for a given half-hour sets the spot price for that trading period.

There is a separate and concurrent Reserve Market and energy and reserve is co-optimised which can mean that reserve constraints impact on energy prices.

3.1.1 Generation

The total generation capacity in New Zealand is currently around 9.1 GW, with 5.6GW in the North Island and 3.5GW in the South Island. More than half of New Zealand's electricity is generated from hydro-electric stations. With the addition of other renewable sources of energy – geothermal, biomass, solar and wind – over 70 percent of New Zealand's electricity production came from renewable energy resources in 2010. The Government's Energy Strategy aims to lift this to 90 percent by 2025. The balance between North Island and South Island will change from year to year depending on hydrological conditions. A further 10% comes from other renewable and waste heat sources (e.g., geothermal, wind) and the remaining 26% from fossil-fuelled plants (oil, coal, gas).

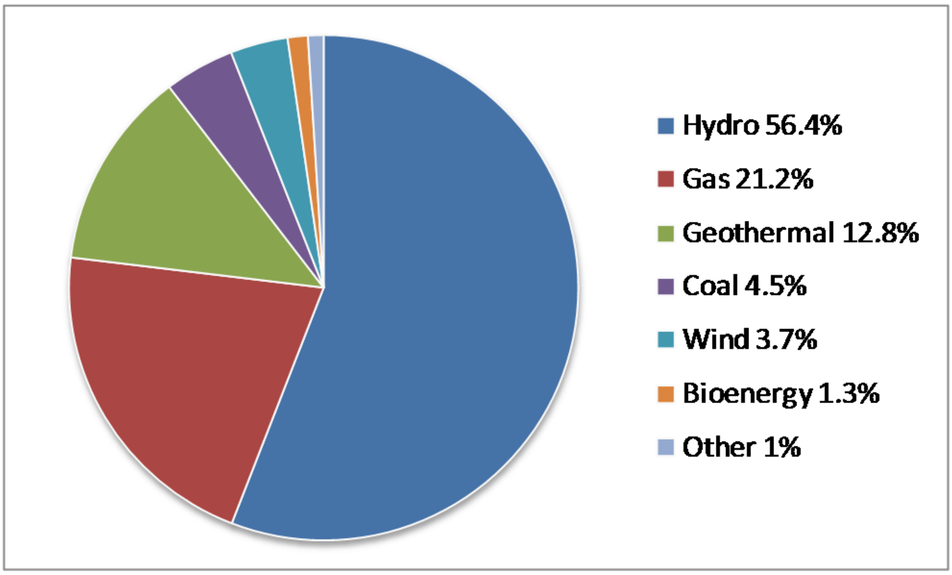

Figure 12: 2010 Generation mix by fuel type (source: Energy Data File 2011)

In 2010, 43,401 GWh of electricity was generated in New Zealand with the five major generating companies providing 91% of New Zealand's electricity generation. These were Meridian Energy (32%), Contact Energy (24%), Genesis Energy (18%), Mighty River Power (13%) and TrustPower (5%).

The introduction of large single-shaft CCGT units has significant impact on small systems such as New Zealand and these now represent the largest single risk on the system (except at times of high HVDC flows).

At the other end of the scale wind generation is expected to increase significantly and this will have implications because of the variable nature of this type of generation. Some predictions see the share of electricity from wind reaching 15 percent in 2030. Looking further out, the general 'rule of thumb' is that wind's annual contribution will settle at around 20 percent. This is because the uneven strength of wind and its variable nature mean wind output needs to be balanced by availability of other generation.

Future developments will focus on renewables, primarily geothermal and wind. Opportunities for expansion of hydro do exist but there are no known plans for new hydro stations at present.

3.1.2 Demand

The Observed Electricity Consumption for 2010 was 39,038GWh, with approximately 62% of energy consumed on North Island and 38% on South Island. Demand varies from year to year, but the overall trend in recent years has been an increase of approximately 2% per year, falling to less than 1% per annum for the four years to 2010. Households account for around a third of total electricity consumption. The commercial and basic metals sectors are also large users, with the Tiwai Point aluminium smelter being the largest single user of electricity in the country.

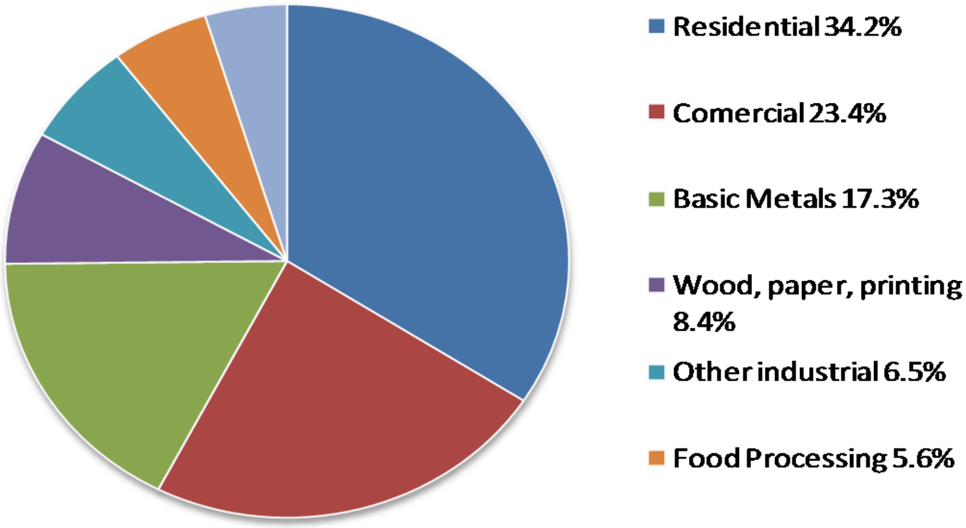

Figure 13: Electricity Consumption by sector in 2010 (source: Energy Data File 2011)

However, demand growth rates vary substantially from region to region due to the geographic pattern of residential, commercial and industrial demand in New Zealand. Thus, for instance, demand in the Auckland region, where commercial and industrial presence is high, the demand is forecast to grow in next 10 years by 45%; whilst in the Otago/Southland region at the bottom of the South Island, demand is forecast to grow by just 11%. In addition to the urban areas of Auckland, Wellington and Christchurch, which are the main electricity consumers of the country, New Zealand also has another major energy consumer which uses 15% of the national energy production - the Tiwai Point Aluminium Smelter in Southland, which effectively has a dedicated power generator in the Manapouri power station.

In 2010 consumption of demand in New Zealand was 39,038 GWh, comprising residential demand (34.2%), commercial demand (23.4%), Basic metals demand (17.3%), agriculture (4.7%) and other industrial demand (20.5%).

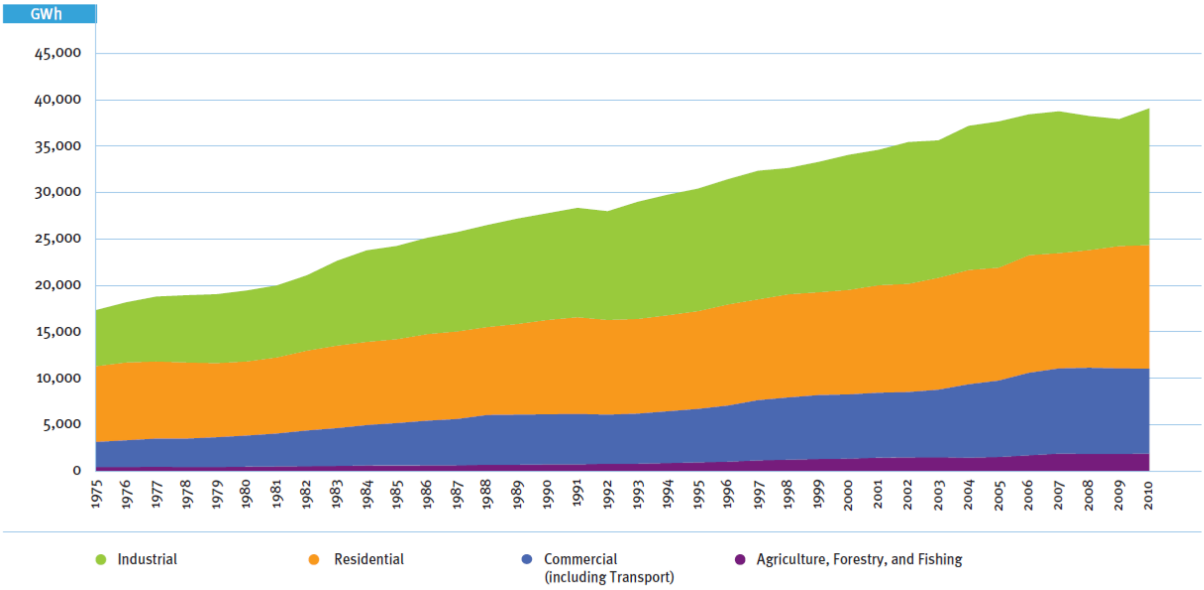

Figure 14: Electricity Consumption in New Zealand by sector (source: Energy Data File 2011)

3.1.3 Network

The New Zealand transmission owner and System Operator is Transpower New Zealand. As outlined above the transmission network in New Zealand consists of networks on each of the North and South Islands linked by an HVDC interconnector. This HVDC link normally has a capacity of 1050MW. The DC flow will vary according to demand, relative prices in North Island and South Island and the source of sufficient reserve to cover the loss of a Pole (the DC is configured as 2 Poles each with a capacity of about 500 MW).

For the combined network, total network length is almost 12,000km with 173 substations. The AC transmission network operates at 220kV, 110kV and 66kV and the HVDC operates at 350kV. Transpower has 46 transmission customers, consisting of 7 generators, 28 distribution companies and 11 transmission connected large industrial customers.

The network can best be described as 'long and stringy' and it is the geographical separation of most generation from demand that causes the main system operation issues (as discussed below) especially in terms of delivering energy to the Auckland region.

From a security of supply and power quality perspective the system is operated as two separate networks but with interconnector flows via the HVDC link, which links the two islands. Each island is required to have sufficient reserve to cover a contingent event within the island, such as the loss of the largest single generating set (120MW in the South Island and 385MW in the North Island). Depending upon the volume and direction of flow the HVDC link often represents the major risk to supply continuity in the North Island.

Without the HVDC link, each island is independent of the other in terms of frequency response and reserves. However with the HVDC reserve sharing functions operating, reserve can be shared between the islands. For example, if the frequency in the North Island drops due to plant loss, the HVDC reserve-sharing functions will increase the HVDC transfer to compensate for the lost generation. In this mode the reserve is being provided from the South Island. Note that New Zealand does not utilise Automatic Generator Control (AGC).

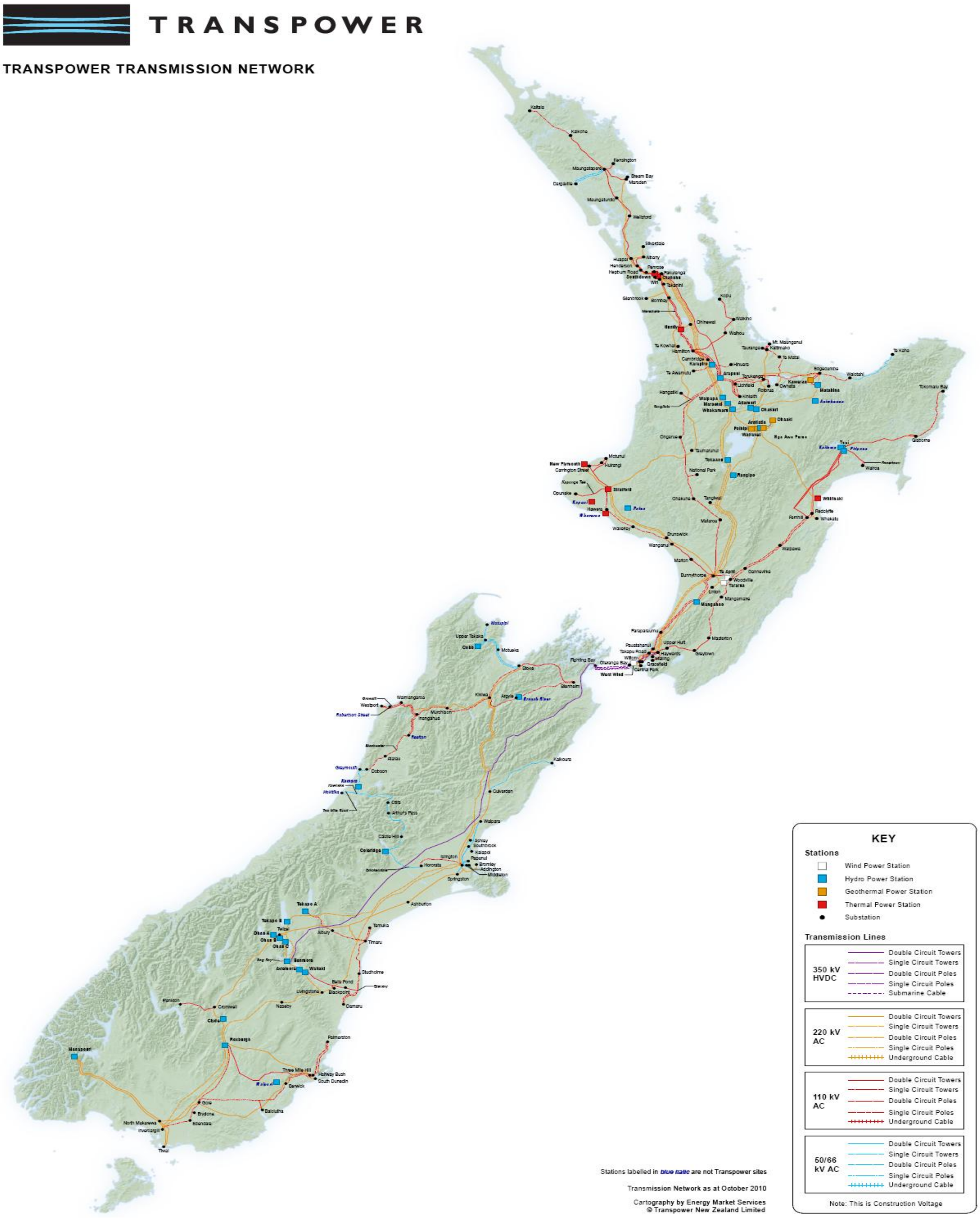

Figure 15: The transmission network in New Zealand (source: Transpower)

Frequency control in New Zealand usually is not an issue due to the high capacity of flexible hydro generation. The major issues for the Transmission System Operator, Transpower, relate to voltage support. There are minor problems in the north of the South Island and major problems in the north of the North Island (the Auckland region). Transmission constraints in the North Island are often due to voltage problems. New Zealand's major demand centre is the Auckland region in the north of the North Island where Auckland has the country's fastest growth and increased use of motive power (primarily air conditioning) has, and continues to exacerbate this situation. Until recently there was little generation is this area consequently energy was mainly sourced from hydro and coal fired power stations in the centre of the North Island and (exported) from South Island via the HVDC link with the inherent disadvantage of significant reactive line losses; as a result additional reactive power support was needed to maintain voltages levels in the region. Since deregulation in 1996 a number of new gas-fired power stations have been built in the North Island, including approximately 600MW of CCGT capacity in Auckland. However there is still a need for dynamic reactive support and Transpower contracts with an Auckland CCGT for reactive power support for this reason. This in itself creates other problems as there is a risk of voltage collapse if this generator or one of the key 220kV transmission lines into the region was to be lost under fault or failure conditions. Under all credible future market development scenarios, demand in the upper North Island (wider Auckland region) will grow at a faster rate than local generation will be built – most economic generation options are located south of the upper North Island. As a consequence Transpower is currently proposing installing additional compensatory equipment including capacitor banks and SVCs (Static Var Compensators) as well as a new 220kV line from central North Island into Auckland, however this is facing significant opposition and the outcome is not yet clear.

The Transpower is developing number of the projects in upper North Island designed to meet the immediate need for additional dynamic reactive capacity until 2015 and enhance the operational management of the power system in the upper North Island. Specifically, the Proposal includes:

- Two STATCOMs to meet the ongoing need for dynamic reactive support;
- A Reactive Power Controller and enhanced System Operator software to ensure the power system is operable in real-time;
- System monitoring equipment to improve SO understanding of the upper North Island power system and so help inform the need for future investment; and
- Demand-side initiatives to allow more flexible management of the grid in the region during major project commissioning and provide an important contingency measure against uncertainties both in the growth and nature of regional demand and the requirement for reactive support.

3.2 Services used by the TSO

The System Operator has contracts with generators, end user customers, retailers and distributors to provide the following system services:

- Frequency keeping - Under the current arrangements, the System Operator is expected to maintain the frequency in each island within a normal band between 49.8 Hz and 50.2 Hz (except for momentary fluctuations) and to maintain system time error. Frequency keeping system services are procured to continuously smooth out moment-by-moment mismatches between generation dispatch and demand. The requirement is for the provision of spare synchronised capacity with a response time sufficiently fast enough to control the frequency (within the normal band for small changes in frequency). Typically this requires governor droop settings of 4-5% and a unit ramping rate of ±10MW/min. Contracted providers submit half hourly offers to the System Operator. In each island, the single provider offering the lowest price in each half hour is selected to keep frequency. In addition to the price offered, the selected provider receives constrained-on or constrained-off payments relative to its energy dispatch. National half-hourly frequency keeping procurement costs (including frequency keeping constrained on and off payments) are allocated to wholesale market purchasers in proportion to the amount of electricity purchased.

- Instantaneous reserves – the provision of interruptible load, partly loaded spinning reserve and/or tail water depressed reserve[5] available to cover unforeseen losses of generation or transmission. The total response expected will be fast enough and in a quantity sufficient to arrest the fall in frequency (fast instantaneous reserve), and assist in the recovery of frequency (sustained instantaneous reserve).

  The reserves to manage under-frequency excursions are scheduled and dispatched based on offers in the Instantaneous Reserve Market. There are two types of reserve required – Fast Instantaneous Reserve (FIR) and Slow Instantaneous Reserve (SIR). FIR is required to respond within 6 seconds of frequency falling and sustain this extra generation for at least 60 seconds. Instantaneous reserve is procured based on the size of the single largest contingent event that could occur during a particular trading period. Generators offer instantaneous reserves at the same time as they make energy offers. SIR is required to respond within 60 seconds of a frequency event and be maintained for up to 15 minutes if required. The division into two classes of reserve is intended to accommodate the differing reserve characteristics of thermal

[5] Spinning reserve may be either partly loaded spinning reserve (PLSR) which is simply a generator that is running and generating, but at a lower output that allows it to increase output quickly in response to low frequency. Some hydro generators can also provide tail-water depressed (TWD) spinning reserve. In this case a hydro generator and turbine are run as a motor from the grid, which means the generator is spinning and synchronised and it can quickly be turned back into a generator in response to low frequency.

generators, hydro generators, and interruptible load. The FIR is intended to rapidly respond to a falling frequency to stop frequency decay, whilst the SIR responds more slowly but is used to restore the frequency to statutory limits.

The Code requires that the system carries sufficient reserves so that any likely contingency event (CE) will result in the frequency falling to no lower than 48 Hz and the System Operator will use reasonable endeavours to return the frequency to greater than 49.8 Hz. The Rules also requires that the system carries sufficient reserves so that any low probability extended contingent event (ECE), will result in the frequency falling to no lower than 45 Hz and the System Operator will use reasonable endeavours to return the frequency to greater than 49.8 Hz.

- Over-frequency reserves (OFR) - these reserves are procured in the South Island to ensure the system frequency remains within acceptable limits should the HVDC or large loads trip. The OFR is implemented by a generator over-frequency tripping scheme which is intended to trip selected units in the South Island in order to limit the over-frequency to 55 Hz in the event of an HVDC bipole trip during North transfer. For both CE and ECE cases, the Code specifies that the frequency rises to no more than 55 Hz and the System Operator will use reasonable endeavours to return the frequency to less than 50.2 Hz. The generators are separated into two zones with different frequency settings so that all generators will not trip at the same time initiating an under-frequency condition.
- Voltage support - Reactive power injection or absorption capability of assets and other reactive power resources provided to maintain voltage at a point of connection to the grid with the objective of avoiding cascade failure and managing voltage fluctuations. Reactive support is procured in particular regions of the grid, essentially Auckland and the top of South Island, to support voltage. The services are procured from generators over and above mandatory provision.
- Black start – Equipment that is made available to enable a generating unit isolated from a grid to be started up and connected to the grid, ready and then able to energise the grid at that grid injection point without any power being obtained from the grid.

3.2.1 Procurement of Services

The System Operator's obligations include preparing a Procurement Plan which sets out the means by which the System Operator will purchase system services in order to effectively operate and manage the system in real time.

System services are procured in line with the following principles:

- Firm Quantity Procurement – Procured on a fixed quantity, fixed price basis where a specific need has been identified by the SO.

- Half-hour Clearing Market Procurement – Procured through a half-hour clearing market process whereby, for each System service, System service agents submit offers to the system operator. Before an offer can be submitted the System service provider must enter into a procurement contract for the particular service sought. The System service procurement contract sets out the offer and the firm price for the service provided.

The SO is responsible for applying one or a combination of the following pricing components in respect of each System Service to be procured in order to deliver the most cost effective delivery:

- Utilisation or Offer Price - The price for the service quantity, expressed in NZ$ or NZ$ per unit capacity of the services provided over the period for which the quantity used is measured and reconciled;

- Availability Price - The price for making the service available, irrespective of dispatch, measured in NZ$ per period of time for which the service is made available; and

- Event Price - Is the price for calling on the system services capacity for a particular event, expressed in NZ$ per event.

In order to achieve the most appropriate balance between cost and quality for each Service provided the SO takes into account the following elements:

- The technical specification of the plant being offered;

- The minimum acceptable service standard; and

- The number of suppliers offering the service and any limitations identified.

Total system service procurement costs have averaged between $100-150 million per annum. The cost of these services is currently of the order of $90m annually, most of which relates to frequency keeping (NZ$53m) and instantaneous reserves procurement costs.

Furthermore, purchasers have significant difficulty in hedging these costs. Unexpected and large variations in the cost of producing some ancillary services, in particular instantaneous reserves and frequency keeping have been a major cause of concern to wholesale purchasers. It is also affecting the wholesale energy price, as generators must restrict energy production if they provide more system services and vice versa. In recent years a number of market participants raised concerns about a rise in constraint payments associated with frequency keeping services and the potential effects of growing levels of variable generation on frequency keeping requirements.

Instantaneous and Frequency keeping costs are shown below:

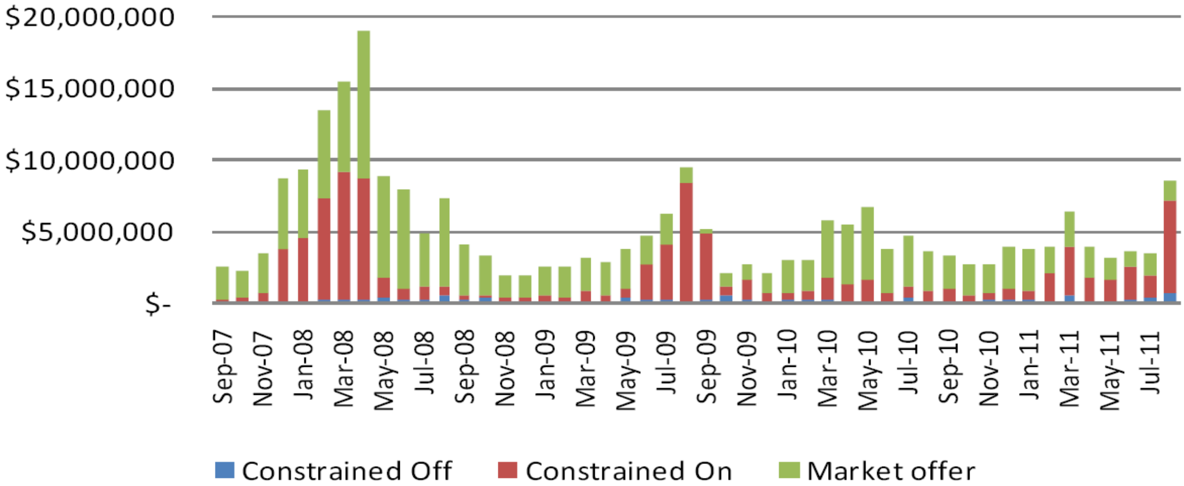

Figure 16: Frequency keeping costs 2007-2011

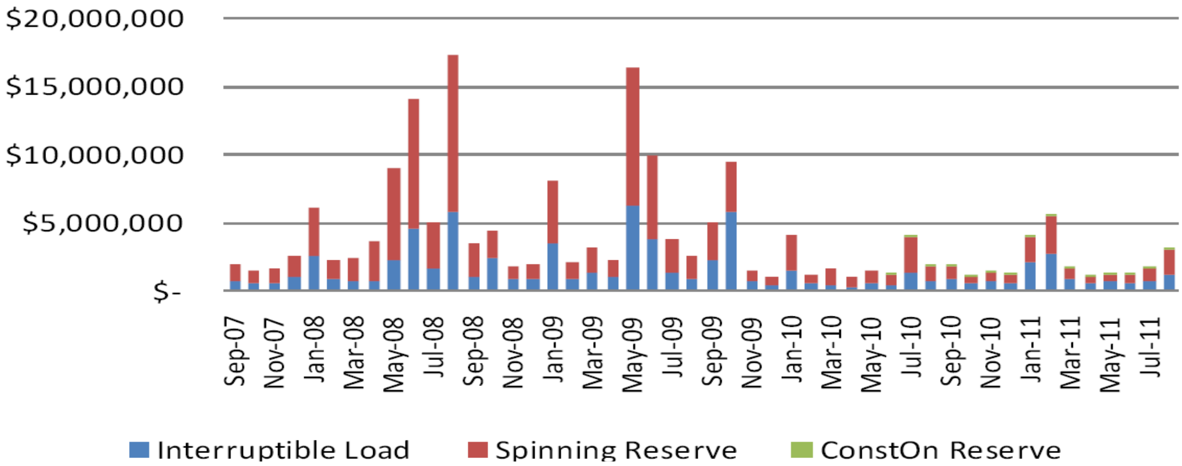

Figure 17: Instantaneous Reserve costs 2007-2011

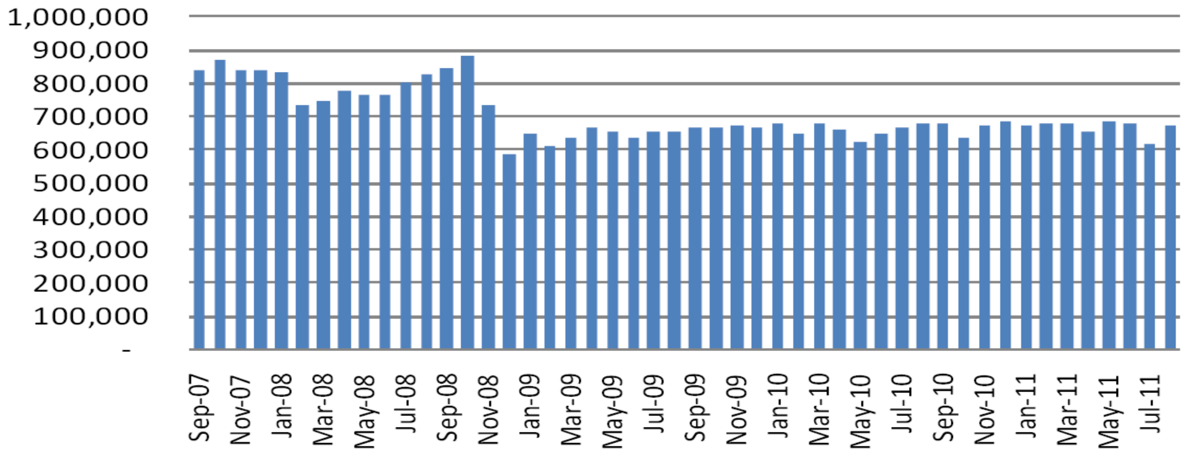

Figure 18: Voltage Support costs 2007-2011

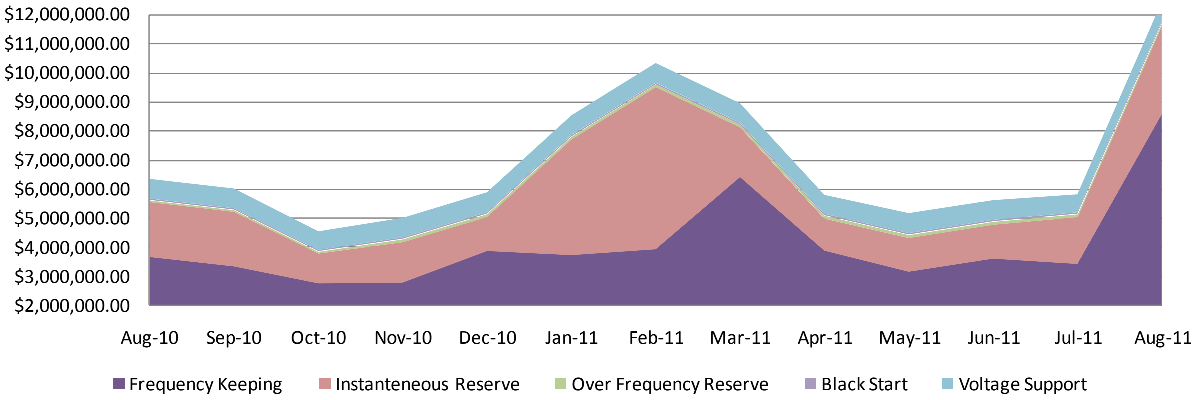

Figure 19: Total system services costs 2011

Unlike the instantaneous reserves market, the number of frequency keeping providers is quite limited with only two generating companies in each island able to meet technical requirements to provide the service, and only one generator in each island selected for duty at any one time. However, the level of frequency keeping services can be expected to increase as more variable generation connects to the system.

The total costs of the system services for the period August 2010/11 are shown in detail in the table below:

		Aug-11	Jul-11	Jun-11	May-11	Apr-11	Mar-11	Feb-11	Jan-11	Dec-10	Nov-10	Oct-10	Sep-10	Aug-10
Frequency Keeping	*Constrained OFF*	785,824	442,543	243,452	173,923	97,273	598,922	110,637	276,352	261,949	232,345	79,942	196,975	157,035
	Constrained On	6,417,651	1,564,284	2,341,842	1,459,962	1,648,632	3,291,059	1,980,478	1,591,074	823,024	448,300	545,477	777,139	770,649
	Market Offer	1,379,957	1,436,934	1,041,331	1,543,392	2,154,680	2,538,776	1,858,116	1,880,150	2,804,161	2,123,231	2,150,645	2,385,395	2,754,539
	Total monthly cost	**8,583,432**	**3,443,761**	**3,626,625**	**3,177,277**	**3,900,585**	**6,428,757**	**3,949,231**	**3,747,576**	**3,889,134**	**2,803,876**	**2,776,064**	**3,359,509**	**3,682,223**
Instanteneous Reserve	*Spinning Reserve*	1,783,099	810,537	508,895	403,999	444,095	833,877	2,799,543	1,855,671	619,155	669,307	454,901	889,172	1,054,917
	Interruptible load	1,233,073	777,063	630,937	743,664	610,410	877,479	2,692,474	2,121,613	529,657	695,584	561,235	965,175	813,957
	Constrained On	39,106	22,655	26,187	12,245	47,058	0	85,343	102	20,306	23,286	10,113	23,842	20,897
	Total monthly Cost	**3,055,278**	**1,610,255**	**1,166,019**	**1,159,908**	**1,101,563**	**1,711,356**	**5,577,360**	**3,977,386**	**1,169,118**	**1,388,177**	**1,026,249**	**1,878,189**	**1,889,771**
Over Frequency Reserve	*Total monthly Cost*	**97,752**	**97,752**	**97,752**	**97,752**	**97,752**	**97,752**	**97,753**	**97,753**	**97,500**	**95,500**	**57,000**	**57,000**	**57,000**
Black Start	*Total monthly Cost*	**45,825**	**45,825**	**45,825**	**45,825**	**45,825**	**45,826**	**45,826**	**45,826**	**45,493**	**41,771**	**41,771**	**41,771**	**41,771**
Voltage Support	*Total monthly Cost*	**675,068**	**618,401**	**678,570**	**686,632**	**652,177**	**676,613**	**678,557**	**674,654**	**686,667**	**674,694**	**638,136**	**680,356**	**678,307**
All Ancillary Services	*Total monthly Cost*	**12,457,355**	**5,815,994**	**5,614,791**	**5,167,394**	**5,797,902**	**8,960,304**	**10,348,727**	**8,543,195**	**5,887,912**	**5,004,018**	**4,539,220**	**6,016,825**	**6,349,072**

These comprise a total of $90.502M which is equivalent of ~ 2%[6] of the total sales in the New Zealand electricity market.

3.2.2 Compliance and Performance Monitoring

The performance and system compliance that must be adhered to by service providers are explained in detail in the system operator (SO) annual procurement plan. This document sets out the process the SO will follow in procuring ancillary services and includes performance monitoring requirements for each of the system services sought.

Each provider is required to measure and record the system service provision data for pre defined periods (the exact time varies for different type of the service). The system service provider must ensure that the data recorded by the monitoring equipment is held by the provider for at least 14 business days and is provided to the system operator within 5 business days of a written request from the system operator.

Where, in the reasonable opinion of the System Operator, the actual performance differs from the offered performance, further plant tests at the expense of the ancillary service agent may be requested by the SO.

3.2.3 Incentives for the TSO

The requirements for system performance, stability and power quality are set out in the System Operator's Principle Performance Obligations contained in the Code and are a stated requirement within the System Operator's Service Provider Agreement.

The Code contains mandatory technical performance capability criteria for all asset owners, including lines and generation; for example: generators are required to meet minimum reactive support capabilities and frequency support capabilities and distributors (Transpower) are required to provide automatic under-frequency load shedding facilities for more extreme system events.

With mandatory obligations requiring the capability for providing the range of services required, the System Operator seeks provision of a range of service contracts through the various half-hourly reserves markets with prices set by participants.

Frequency keeping and reserve services are competitively offered and scheduled through the various reserves markets. Participants are then scheduled at the market clearing price (SMP) for that service. Before participating in these markets providers must hold a system services contract with the System Operator. Voltage support is contracted according to need and geographical requirement. Black start is an open tender process.

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[6] This is based on $5,883M of total electricity sales in the New Zealand (source: Energy Data File 2011)

As such the System Operator has no cost incentive mechanism save a general requirement to procure at reasonable cost, as part of its overarching reasonable and prudent operator requirement. That said the System operator has encouraged the use of alternative sources of reserve, especially interruptible load.

The Code requires that each year the System Operator prepares a draft Procurement Plan which sets out the System Operator's assessment of the system services that are required to be purchased for the System Operator to meet its principal performance obligations in the following 12 months. It also contains key contracting and technical requirements that are required of system services providers.

The Procurement Plan should not of itself create any material liabilities for the System Operator. The System Operator has an obligation to use "reasonable endeavours" to implement the plan and enter into necessary system services agreements. A failure to do so will create an exposure under the requirements for complying with the Principal Performance Obligations that, in substance, is an exposure related to its fundamental obligations to perform the System Operator function. The Code excludes the System Operator from any liability arising from the failure of any system services provider to supply contracted services (procured under the plan).

The only significant financial risk that could arise to the System Operator in respect of system services is in the event that the System Operator departs from the Procurement Plan and as a result incurs additional costs that were not anticipated within the Procurement Plan. Any such additional costs would be unrecoverable by the System Operator as the ability to recover system services costs is intrinsically linked to compliance with the Procurement Plan. It is believed that, to-date, no such departures have occurred.

As far as innovation and incentives are concerned, the Code requires an inclusion in the procurement plan of an assessment by the System Operator of competitive cost pressures and the degree of innovation it believes are involved in the procurement process it is proposing when procuring a system services in general. These are set out in Table 4 below:

Table 4: Procurement of system services by the New Zealand TSO (source: Transpower Procurement Plan)

System service	Competitive cost pressures	Degree of innovation involved in procurement process (the process for future development is described below)
Frequency keeping	***Low*** Frequency keeping has to be supplied separately for each HVAC island, and there are few stations with the capability.	***Medium*** Procurement using half-hour clearing markets. Procurement process in line with international practice for the few markets that do not use AGC (automatic generation control).

		Various long term initiatives to allow greater participation in the frequency keeping market are being actively explored by the system operator, including AGC and the introduction of a national market.
Instantaneous reserve	***Medium to High*** Medium in the South Island as there are a limited number of providers but prices remain very low. High in North Island as there are a variety of interruptible load and generation ***sources***	***High*** Procurement using half-hour clearing markets. New Zealand's co-optimisation of energy and reserves is leading edge in electricity markets internationally. As the delivery of interruptible load reserve is critical in avoiding cascade failure, the system operator must have confidence that reserve will be delivered in a timely manner and in sufficient quantity to avoid such an event. Options for changing measurement and monitoring resolution requirements are to be explored in the short term, with a view to improving overall resolution.
Over frequency Reserve	***Low*** Most South Island generation plant owned by one of two companies	***High*** A novel solution to a New Zealand-specific problem allowing better management of overall reserve costs.
Voltage support	***Low to Medium*** Small number of providers because voltage support requirements tend to be localised.	***Medium*** The combination of generator AOPOs and tendering for alternative solutions is in-line with world standards. Any concept of demand side participation in provision of voltage support would require an amendment to the Part A definition of voltage support. An investigation of the potential for demand side participation should be undertaken by interested industry participants, including the system operator.
Black Start Services	***Medium*** Not many generators have black start capability, but cost of new entry is relatively low.	***Low*** But, simple procurement approach is appropriate given the relatively low cost of this service.

The degree of innovation in system services procurement processes is also reflected in plans for their further development.

3.2.4 Cost Recovery

System services costs are recovered in different ways according to the services sought, as follows:

> Frequency keeping costs are made up of a market cleared offer (utilisation) price (SMP) and constraint costs, where the provider is either constrained-on or-off to provide the necessary MW headroom for the frequency keeping service. Frequency keeping costs are allocated to purchasers based on the proportion of volume of total energy purchased by them.

> Reserves are an integral part of the New Zealand market and so the price of reserves is dependent upon the cleared reserve market price for any half hour, inter-related and co-optimised with energy to obtain the lowest overall system price for energy and reserve. Instantaneous reserve costs are allocated in two parts, availability costs and event charges:

- The availability costs of reserves for a trading period are allocated to generators when their generating units output is above 60 MW and the HVDC owner on the basis of the injections net of instantaneous reserves that they provided. The calculations are carried out separately for the North and South Islands and for each trading period. For HVDC transfers, the injection is calculated based on which island the flow is into and the level of so-called “at risk HVDC transfer”. In other words the availability costs are allocated according to the volume of power provided. When prices are very low, this can have a negative effect on parties willingness to offer into the market.

- An event charge is payable by causer of an under frequency event. . Any event charge that is paid is rebated to those that paid the availability costs during the month in which the event occurred and the two preceding months. The purpose of this arrangement is that if there are no events, the availability cost payments would cover the costs of availability, but if there are events, those that cause them pick up the costs. The event charge can have the effect of making parties that have generating plant (or the HVDC link) that may be prone to failure (and as a consequence cause undesirable frequency events) be reluctant to offer plant at competitive rates (greater exposure to unplanned events) inflating offer prices as a result. Over frequency reserve costs, on the other hand, are allocated to Transpower as the HVDC owner.

Voltage support charges are allocated in three parts on a zonal basis. They require the System Operator to set, annually in advance, a Peak Rate and a Penalty Rate for the allocation of voltage support costs. The System Operator uses a methodology for setting those rates to determine, for each zone, the unique pair of rates that satisfy the following criteria:

- The peak and penalty revenue derived from kVAr data for each distribution companies kVAr reference node (grouped Grid Exit Points-GXPs) will recover the estimated cost of the voltage support contracts, assuming that kVArs at each distribution kVAr reference node are as in the previous calendar year. The 2011 Peak and Penalty rates were 176 cents/ kVAr and 241 cents/ kVAr respectively.

- The penalty rate is equal to or greater than the per unit cost of new high-voltage var support equipment.

Distribution companies are required to nominate (annually in advance) a peak demand in kVAr at each distribution kVAr reference node in each zone. This nomination is for off take only, and should not net off any injection of reactive power.

> Black start costs are allocated to the grid owner.

3.2.5 Evolution of Services

The system services arrangements in New Zealand today are essentially those which were established at the same time as the wholesale market. Because the market operates with both energy and reserve, and the schedule is co-optimised, any developments in one follow those in the other.

There have however been changes with regard to the procurement and utilisation of system services, such as the growth of interruptible load and the increasing size of generation.

Payment mechanisms for reserve have changed in that there is now a higher risk element in the event charge - previously reserve costs were allocated on a 'runway' model according to size of units. However generators claimed that new large units were more reliable than older, smaller units hence the reason for the change. Recent problems with new plant have however meant that some newer plant has been the cause of reserve utilisation resulting in high payments from the generators concerned.

3.2.6 Future Developments

Mention has been made of the issues facing Transpower as the System Operator and Grid Owner - increasing demand in the north, the development of new generation (especially large CCGT units) and the problems associated with variable generation. Transpower is undertaking a programme of work that includes installing more dynamic voltage support equipment (like static var compensators(SVC)) and undertaking demand-side initiatives in the upper North Island in order to maintain voltage levels in the Auckland region, as well as transmission system upgrades and new capacity.

There have been times when a shortage of generation capacity, within a constrained transmission system, has meant that the System Operator has had to signal insufficient reserve margin. In response to power crises in 2001 and 2003 and fears of generation capacity shortages, particularly in 'dry years' when hydro generation has been curtailed, the Government built its own power plant (Whirinak155MW OCGT) which is owned and operated by the Contact Energy since the end of December 2011.

At present, frequency keeping procurement costs are recovered monthly from retailers and direct purchasers, according to their share of national energy purchases. The EA has undertaken a review of the methodology in the Electricity Governance Rules 2003 (Rules) for allocating frequency keeping procurement costs. The review was in part prompted by concerns about the potential impacts of increasing wind generation on frequency keeping requirements. As a result of the review's findings, the EA proposes that the cost allocation methodology should be modified to better target the key contributors to the need for frequency keeping services as a transitional step until more efficient frequency keeping procurement arrangements can be progressed. The general effect of this change is illustrated below. The shaded areas represent total frequency keeping costs.

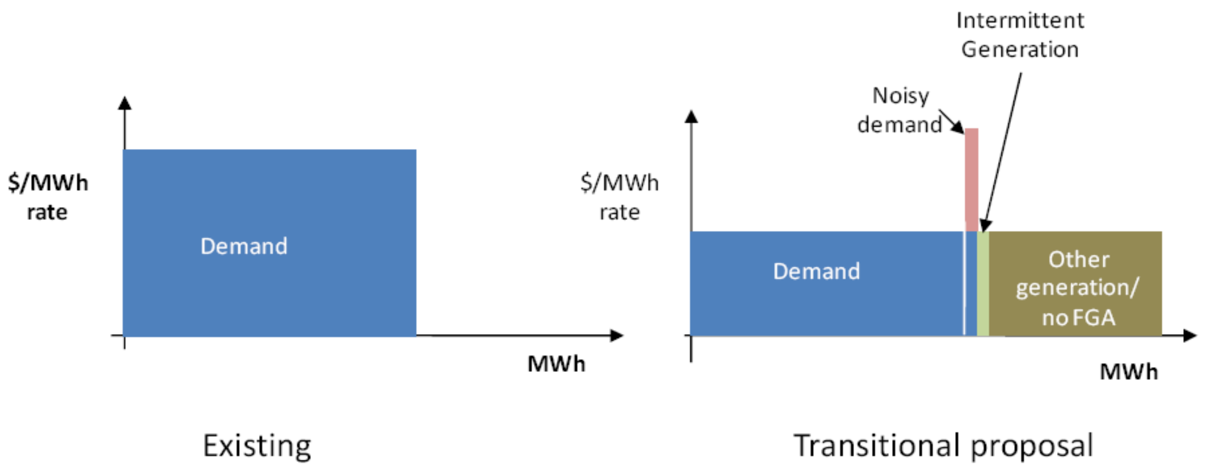


Figure 20: Frequency keeping cost allocation (Source: Electricity Commission Consultation Paper- Frequency keeping Cost Allocation)

Under this approach noisy demand customers would be allocated a share of frequency keeping costs as key influencers and also as demand for residual cost allocation purposes. As illustrated in Figure 22, this would mean that noisy demand purchasers would face a $/MWh charge twice that of normal load and hence would receive a signal equal to the average $/MWh frequency keeping charge to shift from being a "noisy" load to being a "normal" load The proposal would also help to signal that 'noisy demand' and variable generation are likely to face a frequency keeping charge reflecting the cost they impose on the system.

3.3 Summary and Implications

The New Zealand market is effectively 2 island markets linked by a 1GW interconnector. The result is that a great deal of System Service provision to either island is supplied via this link (which represents a high proportion of North or South Island demand) at various times during the year.

New Zealand generation is dominated by flexible hydro plant. This large hydro share of flexible generation helps to compensates for inherent supply weaknesses of a small island system . The low availability of many (run-of-river) hydro stations explains the high plant margin and why weather (dry or wet years) will heavily influence energy prices and costs for the provision of system services. This leads to significant year on year volatility.

Service arrangements have changed little since their introduction in 1996 largely due to the stability in generation mix and relatively low costs of provision. Core service providers are governed and mandated by technical codes with procurement driven by a pre-determined tendering framework that incorporates commercial remuneration, given the strong competition for providing system services in New Zealand (many market participants capable of supplying the range of services sought).

New Zealand has chosen to adopt a relatively integrated market for energy and system services, with regulation and reserve co-optimised within energy dispatch. This again reflects the flexible nature of much of New Zealand's generation. This, unlike other international examples, means that the TSO does not need to seek to “pre-empt” the behaviour of the energy market at any point in time to ensure sufficient dynamic capacity is available to meet security needs within given operational timeframes.

Whilst EirGrid may wish to examine the regulatory and commercial arrangements in New Zealand they should take into account the large hydro presence, relatively heavy island interconnection, and high generator competition, which enable a light regulatory touch and a more integrated market approach to the provision of system services.

The cost of system services is currently of the order of $90m annually and represents around 1.5% of the total sales in the electricity market in New Zealand. Any review of potential lessons from the New Zealand context for the application of system services in the SEM should carefully consider the high proportion of hydro generation that New Zealand benefits from, and the relatively high level of competition for the provision of system services. As explained earlier, a co-optimised approach to both energy production and the provision of services gives support to more efficient and cost effective control of frequency. Additionally, New Zealand, as two islands, also benefits from the ability to use significant transfer capability through the HVDC interconnector joining the two islands. Moreover the topography of New Zealand is very different to any other example, and this necessitates a strong emphasis on reactive power rather than the provision of frequency services.

4. Tasmania

4.1 Introduction and market overview

Until April 2006 Tasmania was an isolated 'island' network, however with the commissioning of the 360km Basslink 400kV HVDC connection between Australia and Tasmania on 28 April 2006 Tasmania became part of the wider eastern Australia interconnected network - see the network diagram provided in Section 4.1.4. Basslink has enabled Tasmania to participate in the Australian market managed by the National Electricity Market Management (NEM) for both energy and for frequency control. Basslink can provide 600MW of electricity into Victoria during the summer months and 480MW into Tasmania during its winter peak.

Disaggregating the former vertically integrated Hydro-Electric Corporation (HEC) created three state-owned entities for generation, transmission and distribution/retail. Generation is provided by Hydro Tasmania, who is responsible for hydro and wind generation. Hydro Tasmania also wholly own Bell Bay Power who operate a 345MW gas-fired power station. Transend Networks are the transmission owner and System Operator. Distribution and supply is the responsibility of Aurora Energy. Retail competition began in July 2006 with deregulation of supply for large customers.

The Tasmanian Government's policy objectives are reflected in the Electricity Supply Industry Act 1995 (ESI Act), which governs the electricity supply industry in Tasmania, and includes the promotion of efficiency and competition in the electricity supply industry and the protection of consumers of electricity. The ESI Act establishes the office of the Regulator, being the three-person body established under the Economic Regulator Act 2009. The amendments to the ESI Act also provided for the development of the Tasmanian Electricity Code (the TEC).

The TEC was based largely on the Australian National Electricity Code (NEC). The different operating structure of the Tasmanian electricity supply industry means that there were some significant differences from the NEC. The Act was modified in November 2004 to enable the structural and regulatory arrangements necessary for Tasmania to enter the Australian National Electricity Market (the NEM). The Act took effect in May 2005, triggering Tasmania's participation in the NEM, and the NEC then became effective in Tasmania. Those parts of the TEC covered by the NEC were be deleted on NEM entry.

The Code has been further reviewed to ensure that it matched the NEM regulatory environment. The process for reviewing the Code was presided over by the Code Change Panel (which was later dissolved in 2009 following further review of the Code). The process is now complete and the revised Code provides detail of the outcomes of the Code change procedure and changes made to the Code by the Minister with effect from NEM entry in Tasmania.

4.1.1 Generation

Tasmania is unique within Australia as the only State that generates a large proportion of its electricity from hydro-electric power schemes. Hydro has been the predominant source of power in Tasmania since the first power stations were built in the early 1900's. The structure of the Tasmanian electricity market is unique in Australia. Due to the predominance of high rainfall and steep terrain, Tasmania's early energy policy was based on the development of hydro resources

The Tasmanian power generation system consists of 34 power stations including 25 hydro-electric stations and two windfarms with an installed capacity of 2802 MW (as of June 2010). A handful of small generation plants provide a further 7 MW of capacity but are not classified as power stations. All of the large-scale generators in Tasmania are owned by the Government, although a number of large-scale wind farms do have part private investment. Generators with a capacity of less than 30 MW are not required to dispatch the electricity they generate via the NEM bidding arrangements, although distribution of their electricity and their integration into the electricity grid is still overseen by the NEM operator.

A characteristic of Tasmania's hydro scheme is the significant water storage capacity of the system. The total useable storage of the hydro-electric scheme is almost 17,000 million cubic metres, equivalent to over 16 months of Tasmania's total electricity generation. To maximise the amount of electricity that may be generated by the combined schemes, and at the same time ensure that generating capacity is available to suit market requirements, requires careful management. At the highest level Hydro Tasmania's water management strategy aims to maintain total storage levels between 30 and 50% of full capacity on the expectation that with median inflows the annual variation would be some 20% of full capacity. The lower level of 30% provides some margin to provide for a dry year when storage levels could be allowed to fall below this mark. In the particularly low inflow period 2004 to 2007 storage levels fell to 17% of full capacity. Regular operation at or below this level is considered unsustainable. Bell Bay thermal power station (BBPS) was built in 1971 as an oil-fired conventional power station to protect against the possibility of a series of dry years. Its operation has been intermittent, primarily providing support during periods of drought. With the completion of the natural gas pipeline under Bass Strait and the ensuing conversion of the two generating units to run on gas, it is expected that BBPS will be run more regularly, with a 60MW average minimum set by its gas supply contract. Ownership of BBPS has been transferred to Bell Bay Power Pty Ltd. This is a wholly-owned subsidiary of the Hydro-Electric Corporation, but became a separate State-owned company at the time that Basslink was commissioned. The Tamar Valley Power Plant (TVPP) is a LNG-fired gas CCGT plant commissioned in 2009 and with a total generating capacity of 390MW it is the single largest generator in Tasmania. It is owned by the Government and operated by Aurora Energy.

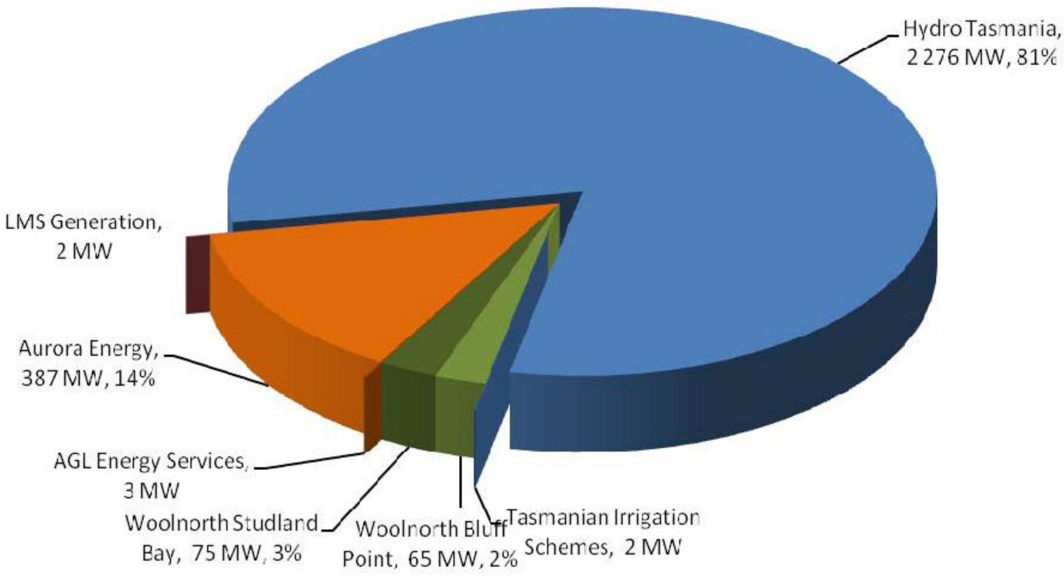


Figure 21: Tasmania's licensed generation (source: Energy Supply Performance Report 2010)

Tasmania's electricity energy requirement is slightly higher than the long-term sustainable capacity of the current hydro system. However, with TVPP and BBPS available to support the hydro system and the introduction of generation from recently introduced wind farms, power generation capacity in the Tasmanian market exceeds current and foreseeable Tasmanian demand at least to 2020.

Tasmania's ability to generate electricity is constrained by the availability of water, rather than the capacity of its power stations. The yield from the water catchments and storages is subject to significant variability and unpredictability. As supply significantly outstrips demand (and medium term forecast demand) additional market-based new entry generation is not sought or required in the short to medium term, indicating that effective competition will not develop in generation over that timeframe.

4.1.2 Demand

The total demand for electricity on mainland Tasmania is typically around 10,800 GWh per annum. This represents 4.9% of total electricity consumption in the NEM. Out of that, around 60% is attributable to a group of 20 large industrial customers, with the remainder being split between business and residential customers. The maximum demand for the year in Tasmania, recorded on 11 August 2005 (mid-winter), was 1,808MW. However, since Basslink went into service, maximum demand has increased by 17 per cent to a new peak of 2,111MW, recorded on 30 May 2006, this is the sum of local Tasmanian demand and export to Victoria and highlights the significant impact of Basslink on the Tasmanian power system.

Average electricity consumption per customer in Tasmania for the year ended 30 June 2010 was 38.7 MWh, a marginal decrease on the previous year's 38.8 MWh average. If large industrial customers are excluded, average electricity consumption in Tasmania is comparable to the average levels in Australia where consumption is not dominated by a small number of large users.

System load is highly seasonal, with daily peaks varying from around 1,300MW in mid-summer to just under 1,900MW in mid-winter. Of that, around 700 MW is attributable to the major industrial users, meaning that Tasmania's winter peak in demand is mainly due to the electricity used for space and water heating. In other states and territories peak demand occurs in summer.

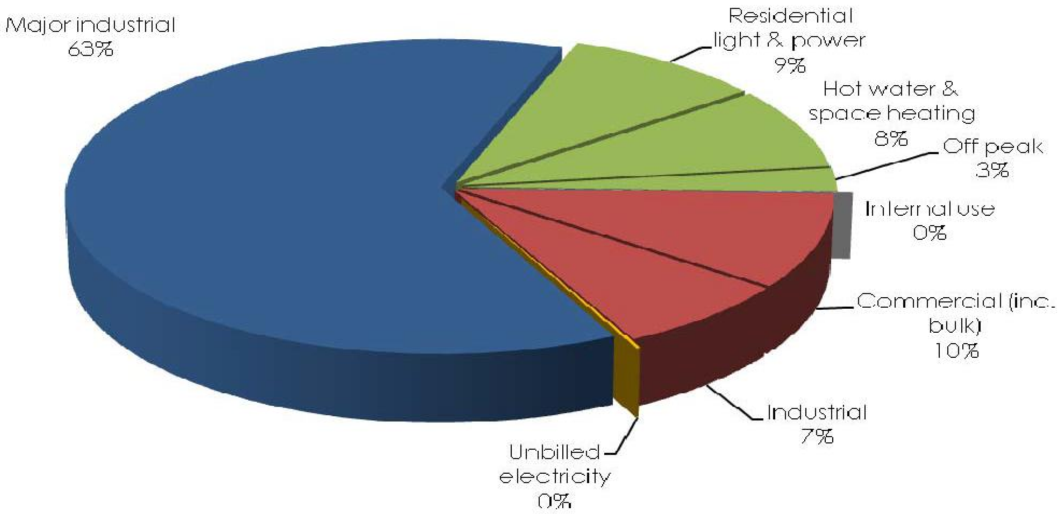


Figure 22: Tasmanian electricity consumption by customer type (source Aurora Energy)

Transend Networks' most recent estimates for the period up to 2024, project average annual growth in electrical energy sales of 0.82% and a 1.71% average increase in the level of maximum demand during winter. On this basis, Transend Networks formed the view that Tasmania's existing generation capacity, together with Basslink southwards flows, will be sufficient to meet forecast maximum demand until 2028.

4.1.3 Network

Transend Networks Pty Ltd owns and operates the electricity transmission system in Tasmania. Transend transmits electricity from power stations to substations around the State and its assets range from 88kV-220kV, with the majority of its assets at 110kV and 220kV. The company owns 2,342 km and 3,516 km of transmission lines operating at 220kV, 110kV respectively. Tasmania's transmission network is the smallest in the NEM, in terms of line length, volume of electricity and asset value. However, the average utilisation of Tasmania's transmission network is high because the major industrial consumers that make up a high proportion of the demand for electricity maintain fairly flat (high load factor) load profiles.

Transend is registered with NEMMCO as a participant in Australia's National Electricity Market (NEM). The NEM operates on an interconnected power system that extends from Queensland to South Australia. The interconnected system was extended in 2006 when the Tasmanian power system was physically connected to the NEM via the Basslink. Basslink is a 360km 400kV HVDC circuit, including 290km of undersea cable, owned and operated by CitySpring Infrastructure Trust who acquired it from National Grid in July 2007. Basslink is a Market Network Service Provider (MNSP) who sits outside regulated charges arrangements, and is required to earn its revenues in a way similar to generators by bidding its capacity into the spot market, with the returns determined by price differences between Victoria and Tasmania. An illustration of the Tasmania network and its connection via the Basslink to the mainland of Australia is provided below:

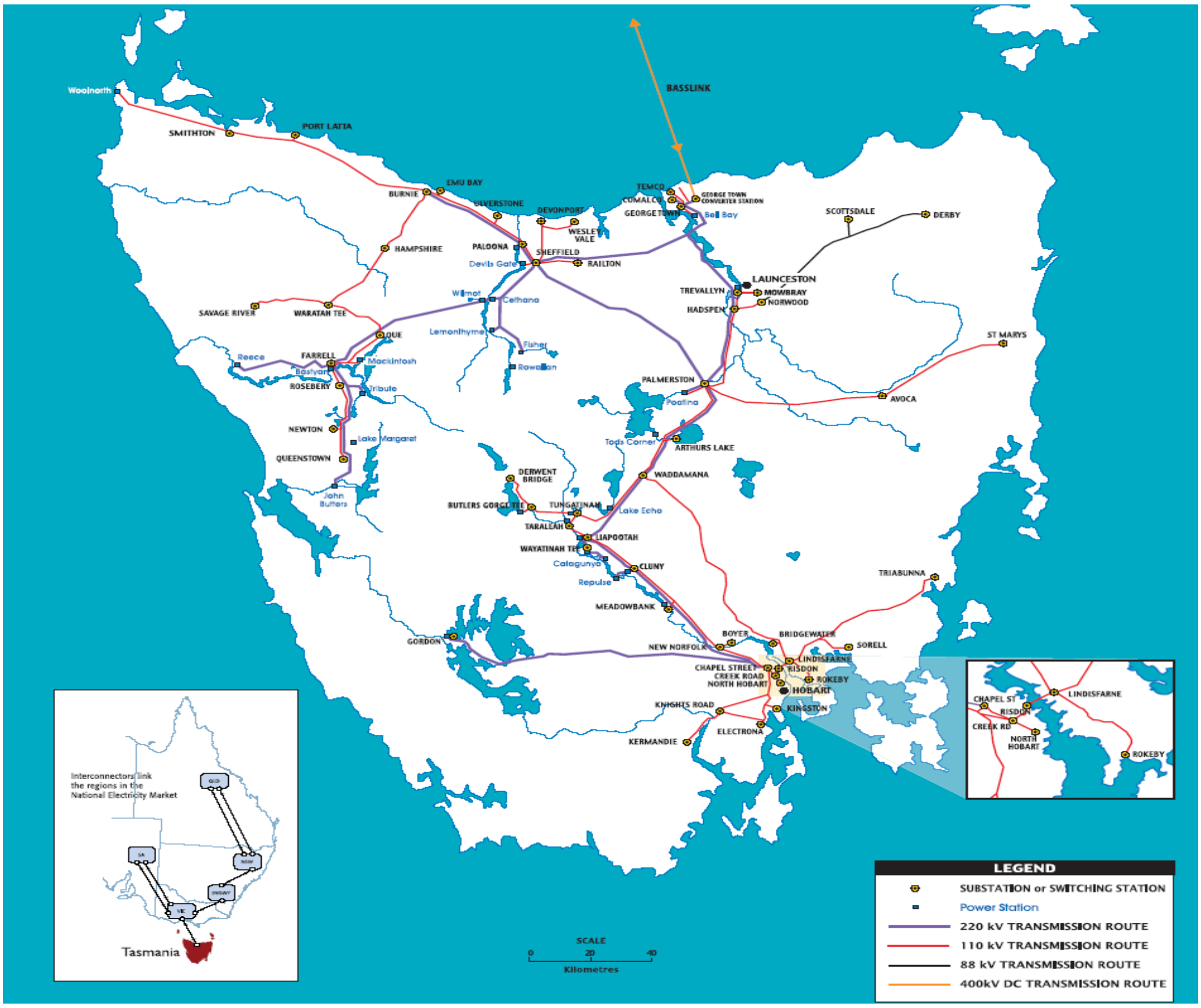


Figure 23: Tasmania's transmission system and its Basslink connection to mainland (source: Transend

The level of supply security offered at a substation is measured by how much redundancy is included in the design of the network. A 'firm' connection point is able to continue supply if a major item of transmission plant is disconnected, as distinct from a ‘non-firm’ connection point where supply would be lost in similar circumstances. Transend has 31 firm and 21 non-firm connection points with distribution connection points and 9 firm and 7 non-firm connection points with directly connected customers.

4.2 Services Used by the TSO

Tasmania joined the National Electricity Market (NEM) on 29 May 2005. On that date, control of the Tasmanian power system was transferred from the Tasmanian System Controller to the NEMMCO. As an interconnected part of the Australian NEM system services in Tasmania are based on standard NEM practice, subject to limitations of the DC interconnection. Similarly the energy market in Tasmania is part of the NEM energy market. The Australian Energy Market Operator Limited (AEMO) is responsible under the National Electricity Rules (Rules) for ensuring that the power system is operated in a safe, secure and reliable manner. The Rules provide for AEMO to purchase these services, from market participants via Market System Service Arrangements or System Service Agreements.

All system services can be divided into the following categories:

(i) Frequency Control system services (FCAS). In order to maintain the frequency to within the NEM frequency standards, FCAS have been developed to maintain the generation / demand balance.

(ii) Network Control system services (NCAS). These are non-market system services used to manage voltage magnitude and interconnector network power flows. The NEM Rules set out minimum requirements for MVAr capability, AEMO only uses NCAS when requirements are greater than mandatory provision. The situation in Tasmania is that voltage is not a significant issue.

(iii) System Restart system services (SRAS). These are also non-market system services that are used to restart the system following a complete or partial blackout.

Frequency Control

Frequency control can be split into two categories:

- **Regulation frequency control** which can be described as the correction of the generation / demand balance in response to minor deviations in load or generation.
- **Contingency frequency control** which represents the changes in generation / demand balance following a major system event (loss of a large generator or a credible network fault).

Regulation services are controlled centrally from National Dispatch Centres and are provided by generators on Automatic Generation Control (AGC). Contingency services are controlled locally and are triggered by the frequency deviation that follows a contingent event. Under the NEM frequency standards, following a single contingency event the frequency deviation must remain within the single contingency band and return to the normal operating band within five minutes. Frequency control standards have led to the classification of eight FCAS requirements. The definition of eight separate FCAS requirements has directly led to the development of eight distinct FCAS markets, see table entries below:

Table 5: Frequency Control system services for Tasmania

Service Class	Service Name	Description
Regulation	Raise regulation (increase generation or reduce load)	Continuous correction of small frequency deviations and time-error correction. The control action is implemented by a centralised Automatic Generation Control (AGC) system. Service providers have their set points continually adjusted to either provide more generation or less net generation.
	Lower regulation (decrease generation or increase load)	
Contingency	6-second raise (fast raise) 6-second lower (fast lower)	Fast instantaneous reserve - fast-acting automatic response to arrest frequency deviations within the first 6 seconds after a large disturbance; examples include governor response and under-frequency load shedding.
	60-second raise (slow raise) 60-second lower (slow lower)	Sustained instantaneous reserve -a slower-acting automatic governor response to stabilize frequency deviations within 60 seconds of a large disturbance.
	5 – minute raise (delayed raise) 5 – minute lower (delayed lower)	Response to return the system to a normal frequency operating band within 5-minutes of a large disturbance. For example, rapid hydro unit loading or unloading.

The inclusion of Tasmania in the NEM enables Tasmanian Market Participants to participate in the FCAS spot markets.

Network Control (NCAS)

Network Control can be split into two categories:

> **Voltage Control** represents methods of controlling voltages on the system through the dispatch of voltage control system services.

> **Network Loading Control** which represents system services used to control the flow on interconnectors within short term limits. For example, if the flow on an inter-connector from region A to region B exceeds the short term limit, AEMO could reduce the flow by increasing the generation levels of generators in region B, or by shedding load in region B.

System Restart (SRAS)

System restart system services are required to enable the system to be restarted following a complete or partial system black. This can be provided by two separate technologies:

> **General Restart Source:** Generator that can start and supply energy to the transmission grid without any external source of supply.

> **Trip to House Load:** Generator that can, on sensing a system failure, trip to feed its own internal load and continue to generate until the system is restored.

Both NCAS and SRAS are provided to the market under long term System service contracts negotiated between AEMO and the participant providing the service. These services are paid for through a mixture of:

> **Enabling Payments:** Made only when the service is specifically enabled.

> **Availability Payments:** Made for every trading interval that the service is available.

The Network Control and System Restart System Services are geographically limited to being required within Tasmania and have not been affected by Basslink commissioning.

AEMO has dual roles as Market Operator and System Operator of the NEM under the National Electricity Rules. In addition to regulation services, sufficient contingency FCAS capability is enabled by AEMO as part of the dispatch process to manage the power system frequency during a contingent event so that it remains within the frequency operating standards as set by the Reliability Panel.

It has been the intention that security of supply and competition benefits will be realised if Frequency Control system services can be traded across Basslink rather than having a separate market for Tasmania (and efficiency benefits for market operation) if Tasmania as an operating region can be treated the same as all other regions. To realise these benefits, it was necessary to find a method of allowing Frequency Control system services to flow across Basslink, subject to the central dispatch process. AEMO has also needed to incorporate Tasmanian regulating plant into its automatic generation control (AGC) system. Because the interconnection is a DC link, it has also been necessary to;

> Make Frequency Control System Services flow on Basslink;

> Provide a control system to regulate power system frequency in Tasmania; and

> Take these into account when dispatching Frequency Control System Services.

The concept used is that for a loss of generation in Tasmania, additional generation would be automatically provided if scheduled (including via Basslink) to control frequency deviations within Tasmania. Consequently a deviation in Tasmania would to a certain extent affect mainland generation, and vice versa. It incorporates a frequency control system that will respond to differences in frequency between the mainland and Tasmania and allow the transfer of Frequency Control System Services between Tasmania and the mainland and vice versa.

A number of dedicated control schemes have been introduced with Basslink including:

> A Network Control System Protection Scheme (NCSPS) which is designed to ensure that power system security is maintained following loss of certain transmission elements in the Tasmanian system; and

> A Frequency Control System Protection Scheme (FCSPS) which is designed to ensure that following loss of Basslink the Tasmanian frequency remains within Tasmanian frequency standards by providing high-speed shedding of generation during export and contracted customer loads during import.

When the Basslink frequency controller is not in service or Basslink is constrained from importing FCAS services from the mainland (which was the case pre-Basslink), the Tasmanian local FCAS enablement must always be equal to or larger than the minimum required to cover credible contingencies in Tasmania. This is not a requirement when services can be sourced through Basslink. Consequently there are periods when no local services are enabled in Tasmania. Similarly there are other times when local FCAS enablement is larger than the local requirement in order to meet global FCAS requirements during FCAS export to the remainder of the NEM.

4.2.1 Procurement of Services

Participants must register with AEMO for each of the 8 FCAS markets in which they wish to partake. Once registered a Participant submits an appropriate bid or offer according to the service (raise or lower). During each and every dispatch interval of the market, AEMO's dispatch engine (SPD) must enable a sufficient amount of each of the eight FCAS products, from the FCAS bids submitted, to meet the FCAS MW requirement. SPD will enable MW

FCAS offers in merit order of cost. Figure 24 shows that highest cost offer to be enabled will set the marginal price for the FCAS category where scheduling is carried out on a co-optimal energy cost basis.

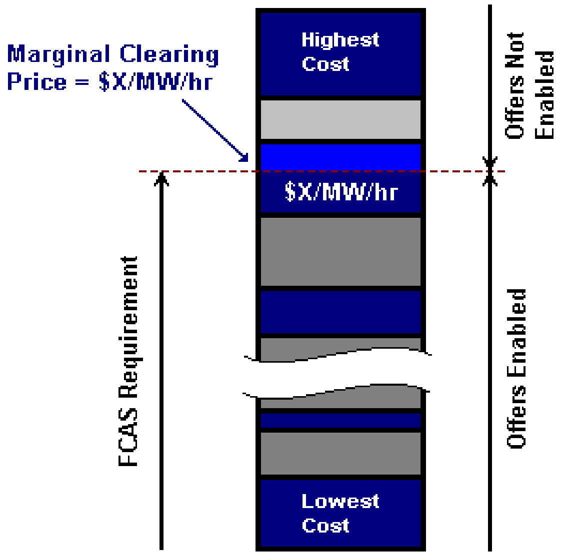


Figure 24: FCAS Marginal Clearing price (source: Power Exchange Operations)

Network Control services (NCAS) are provided to the market under long-term contracts between AEMO and the provider. Services are paid as Availability Payments for every trading period that the service is available and Enabling Payments when the service is specifically enabled.

Table 6: Procurement of system services for Tasmania

Service	Mode	Payment
Voltage Control	Synchronous compensation	Enabling
	Generation mode	Availability
Network Control	AGC	Enabling
	Load shedding	Enabling
System Restart	Generation or trip-to-house load	Availability

Network system services are recovered from market customers (demand) while System Restart costs are levied on both generation and demand (50/50).

4.2.2 Incentives for Providers and the TSO

All market participants must meet mandatory standards as laid out in the NEM Rules; this will include governor and ramping capability, MVAr capability etc. For frequency control, participants will offer into the market and will be selected on a price basis (subject to technical criteria). For Network Control services AEMO as System Operator will firstly utilise mandatory provision and then, when necessary, contract for additional levels of service. For System Restart this will be based on open tender submissions. KEMA has been unable to identify any further incentives during the course of this review.

4.2.3 Cost Recovery

For each 5 minute dispatch interval of the market, SPD determines a clearing price for each of the eight FCAS. This price is then used by settlements to determine payments to each of the FCAS providers, for each of the eight FCAS, under the following formula:

Payment = MWE x CP / 12

(Where MWE is the amount of MWs enabled by SPD for the service being settled and CP is the clearing price for the service in that dispatch interval).

All payments to frequency control System service providers are recovered from market participants according to the recovery rules. The figure below outlines how the costs of system services are recovered in Tasmania:

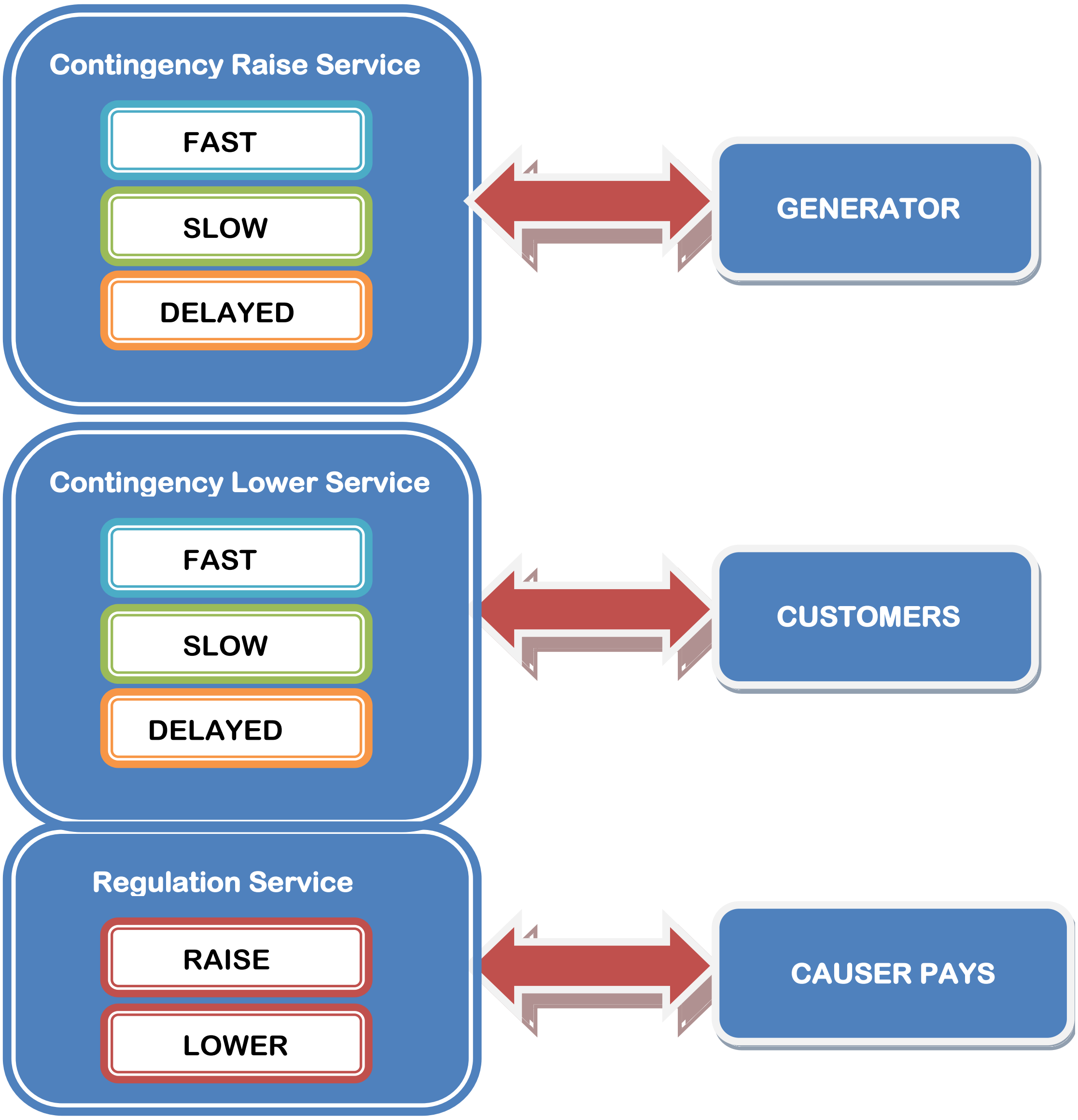


Figure 25: Types of system services

As 'contingency raise' requirements are set to manage the loss of the largest generator on the system, all payments for these three services are recovered from generators. On the other hand, as 'contingency lower' requirements are set to manage the loss of the largest load/transmission element on the system, all payments for these services are recovered from customers. Recovery for contingency services is pro-rated over participants based on the energy generation or consumption in the trading interval.

The recovery of payments for the regulation services is based upon the 'Causer Pays' methodology. Under this methodology the response of measured generators and loads, to frequency deviations, is monitored and used to determine a series of causer pays factors. Participants whose measured entities operate in a manner that assists in the correction of frequency deviations would be assigned a low causer pays factor while those whose measured entities operate in a manner that cause the frequency to deviate would be assigned a high factor. All non measured entities (customers without SCADA) are assigned causer pays factors based upon the remainder (causers not accounted for by measured entities) and based upon their energy consumption in the trading interval being settled. For each trading interval of the market, total regulation payments are recovered from participants on the basis of these 'causer pays' factors.

For the purpose of FCAS payments and recovery, the market is treated globally. Hence, for the purpose of recovery, participants are treated equally, regardless of region.

The calculations represent the deviations from a reference trajectory. The deviations are calculated every four seconds and averaged over a Dispatch Interval. The average results are referred to as five-minute factors.

Monthly causer pays factors are determined based on twenty-eight days of five-minute factors.

Causer pays factors are explicitly calculated for the following:

> All market scheduled generating units;

> All scheduled loads.

Contingency raise FCAS costs are recovered from generators; contingency lower FCAS costs are recovered from demands.

The value of system services is small compared with the value of the energy market, although there is some evidence that the value is increasing. The total weekly cost (September 2011) of system services in Tasmania was AU$211,180, equivalent to around 1.5 per cent of the turnover in the energy market in Tasmania, and includes the costs of all eight Frequency Control System Services.

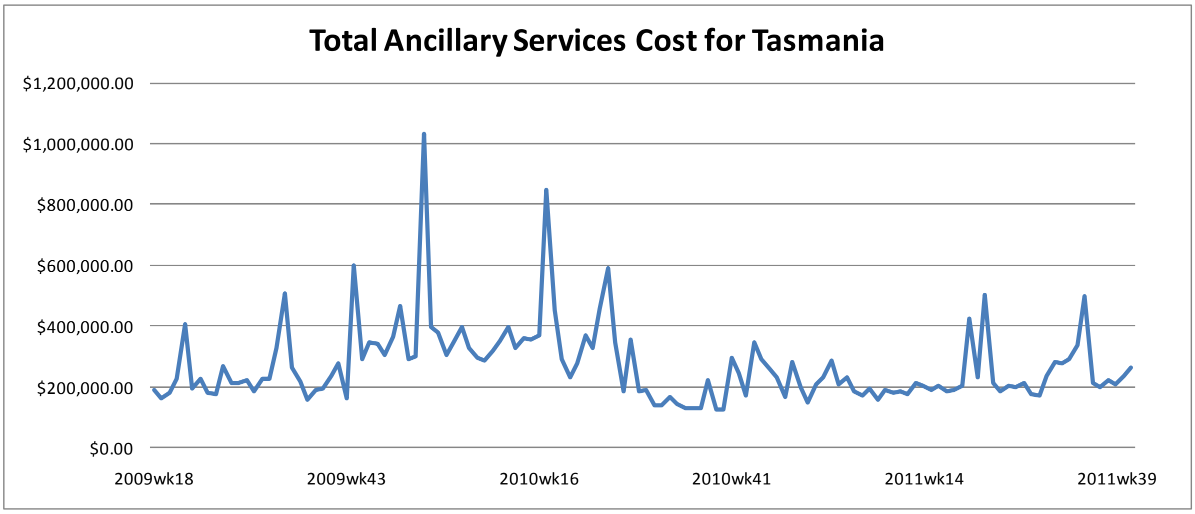


Figure 26: Total daily costs of system services for Tasmania (source:AEMO)

The costs of the SRAS service[7] is around AU$106k weekly on average.

4.2.4 Compliance and Performance Monitoring

AEMO is required to maintain the power system (frequency) and time deviation within the limits specified in the frequency operating standards determined for the Tasmania by the Reliability Panel.

The Frequency and Time Deviation Monitoring Reports are prepared by AEMO on a monthly basis. In the reports, AEMO identifies power system events where the operational frequency deviates from the operating standards and evaluates these performances. The reports describe the power system frequency and time deviation performance and include statistical analyses but do not include individual participant performance.

Performance monitoring for Market Based Ancillary Service (FCAS) is defined in the AEMO FCAS Operational Procedure.[8] It clearly states that if provider fails to respond in the expected manner (*"as determined in POWER SYSTEM OPERATIONS' reasonable opinion"*) or any information is brought to the attention of SO then:

- The participant is to be declared and identified as non-conforming;
- Participant needs to be advised that the unit is identified as non-conforming, and SO requests a reason for the non-compliance.
- SO may set a fixed constraint for the relevant ancillary service for the ancillary service provider.

[7] Cost recovered form all market participants
[8] http://aemo.com.au/electricityops/3708.html

This event will then be forwarded to Power System Performance division for further consideration.

The performance compliance for the Non-Market Ancillary Services - NCAS and SRAS are addressed through the Ancillary Services Agreements. If AEMO suspects participants non-compliance then any relevant information shall be passed to AEMO's System Operations Planning and Performance group.

4.2.5 Evolution of Services

Service provision in Tasmania has evolved over time; in the first instance when Tasmania joined the NEM (May 2005) and came under the jurisdiction and control of AEMO (NEMMCO until July 2009) and then when Basslink was commissioned in April 2006. Prior to joining NEM Tasmania essentially operated as a single utility structure.

The most significant impact has been the commissioning of the Basslink which has enabled participation in the NEM for both energy and FCAS. This has however, not been without problems and the Tasmanian Distributor Aurora has expressed concerns to AEMO over "…the tight supply of FCAS services in Tasmania", noting that the supply of FCAS is much more scarce in Tasmania than in other regions of the NEM.

A comparison of the dispatch data for June and July 2005 with the same period in 2006 indicates that FCAS provision for Tasmanian generators for all services is lower post-Basslink, with the exception of the slow raise and delayed raise services where no significant change is evident.

However, the operation of the Tasmanian power system requires special consideration with regard to FCAS because a large proportion of the installed hydro electric generators are unable to change their output rapidly and hence there is a limited amount of fast FCAS services available, in particular, fast lower services.

In 2010 the Regulator completed its investigation into the pricing policies of Hydro Tasmania in its supply of raise contingency frequency control System Services (FCAS) to meet the Tasmanian local requirement summary. The purposes of the investigation and the subsequent decisions flowing from it have been to promote efficiency and competition in the Tasmanian power supply sector. Following completion of the investigation, the Regulator has decided that:

- The price control mechanism to be applied to Hydro Tasmania shall be by the regulation of Hydro Tasmania's provision and pricing of FCAS contracts;
- Hydro Tasmania will be required to offer a 'safety net' contract to other Tasmanian generators that are not subject to any special conditions other than those relating to self-provision and new sources of supply.

The price of the FCAS 'safety net' contract will represent Hydro Tasmania's costs of physically delivering to the spot market the amount of FCAS nominated in the 'safety net' contract.

4.2.6 Future Developments

Due to planned increases in wind energy penetration and large imports over Basslink (both sources unable to provide inertia to the system) the Government has established an Inertia Issues working group (IIWG) which sits under a body known as the Electricity Technical Advisory Committee (ETAC). In September 2010, the IIWG issued a report highlighting potential issues with inertia and reduced fault levels arising from high wind generation. The AEMO is conducting the consultation required for the preparation of the Network Support and Control Ancillary Services Description (NSCAS Description) and Network Support and Control Ancillary Services Quantity Procedure (NSCAS Quantity Procedure) which will apply from 5 April 2012. With this in mind AEMO has divided NSCAS into the following types[9]:

- **Network loading ancillary service (NLAS);** Examples of NLAS provision include standby generation capable of being brought online rapidly, fast runback of scheduled generating units, reducing load in response to certain signals etc

- **Voltage control ancillary service (VCAS);** It can be provided from unused reactive power capacities of generating units, including wind farms, solar power generating units and any other forms of electricity generating units

- **Transient stability ancillary service (TSAS);** This service will be designed to increase networks transient stability limit. This can be achieved in number of ways including increasing system inertia, better system voltage regulation, reducing system impedance etc.

In response to its First Stage Notice of Consultation a number of possible new system services that could be explained as Non-Market Ancillary Services (NMAS) have been proposed:

- Machine inertia - where system security requires additional inertia and units are in service to provide the additional inertia. There is presently no means of compensation for this voluntary participant action.

- Additional fault level - similar to above where system fault level constraints are resolved by running additional plant in synchronous condenser (SCO) mode.

[9] As explained in AEMO Network Support and Control Ancillary Service (NSCAS) Description document (source: www.aemo.com.au)

> Control of generator AVR - as part of an automated voltage control scheme - voltage control schemes that coordinate generator reactive power with other reactive compensation methods. This could lead to significant reduction in voltage constraints and network losses.

> Network control system protection scheme NCSPS - Permits loading of N-1 transmission line pairs to almost continuous rating through a generation shedding scheme. Such schemes could be more widely applied if generation participation were through a contracted NSCAS.

With 80% of hydro, Tasmania is well placed to manage the impacts of variable generation. However if wind generation displaces conventional generation, lack of inertia would be an important issue that would be bound to affect system security. At this point in time it is not possible to tell if new system services will be created to manage the highlighted system inertia and fault level issues. However if this is of particular interest we suggest keeping a watching brief on the market in Tasmania.

4.3 Summary and Implications

Tasmania is dominated by Hydro generation, which makes over 80% of its capacity. Tasmania is also heavily interconnected (in relative terms to its island demand) to mainland Australia via the Basslink) which makes up 25% of peak demand.

The size of Tasmania (and thus its demand and network) means that the principle focus is on frequency control. The mixture of a large hydro presence and interconnection to the larger Australian mainland system both reduce the System Requirement and enable it to be met at relatively low cost.

The current system services arrangements effectively came into force with the commencement of Basslink operations which allowed Tasmania to join the wider Australia energy market. Consequently Tasmania simply adopted arrangements already in place in Australia under NEMCO which have changed little since they were introduced in the mid 1990s.

Core system services capabilities are mandated by technical codes with procurement driven by market tender based approaches and supporting commercial arrangements, given strong competition for service provision in Tasmania and the provision of services via Basslink (i.e. many market participants capable of supplying all sought system services). As for New Zealand, Tasmania adopts an integrated approach to energy and regulation/reserve markets. Again this reflects the high proportion of hydro in the generation mix which reduces TSO concerns about having the “right” plant running or available in operational timeframes.

A significant increase in wind energy will increase the volatility of very short run imbalances in supply and demand, increasing the volume of system services required (FCAS in particular) to maintain a given level of security and reliability. It is also possible that technological developments in the future might lead to an increasing volume of 'non scheduled' generation, which would further increase FCAS requirement. These developments suggest that the system services requirements and thus energy costs could rise significantly in the future, raising questions as to whether the current FCAS market design should be changed.

The high level of interconnection and the amount of hydro capacity limits the comparisons that can be drawn with SEM.

In summary, any review of potential lessons from the Tasmania context for the application of system services in the SEM should carefully consider the high penetration of hydro generation on the island and the fact that whilst it does have a monopoly generator, Tasmania is effectively now included as a small part of a much larger Australian market (NEM). Furthermore the very large size of the interconnection (as a proportion of island demand) between Tasmania and mainland Australia reinforces the high level of competition for any System Service provision that may be required. The value of system services is equivalent to around 1.5 per cent of the turnover in the energy market in Tasmania. Due to the small size of the island and associated small load and generation the need for reactive power is also very low. Hence in general the costs of system services are lower than for an island of the scale of Ireland especially given the comparative mix of generation.

5. Singapore

5.1 Introduction and market overview

The Singapore electricity industry had traditionally been vertically integrated and Government-owned. In early 1995 the government of Singapore took the decision to begin liberalisation of the Singapore Electricity Market. This culminated in the establishment of the Singapore Power Pool, a day ahead market modelled closely on the Power Pool of England & Wales at the time. The Singapore Power Pool was intended predominantly to encourage generation competition and was established with a Single Buyer Model. In January of 2003 Singapore embarked on the next stage of liberalisation with the introduction of the NEMS (National Electricity Market of Singapore). In the NEMS, which is essentially a real-time electricity trading pool, generation companies compete to sell electricity every half-hour with LMP (Locational Marginal Price) model closely allied to the market models of New Zealand and Australia. With this came the inclusion of the system services of Reserve and Regulation in the Spot Market and the transition from Single to Multiple Buyers together with the opening of retail competition.

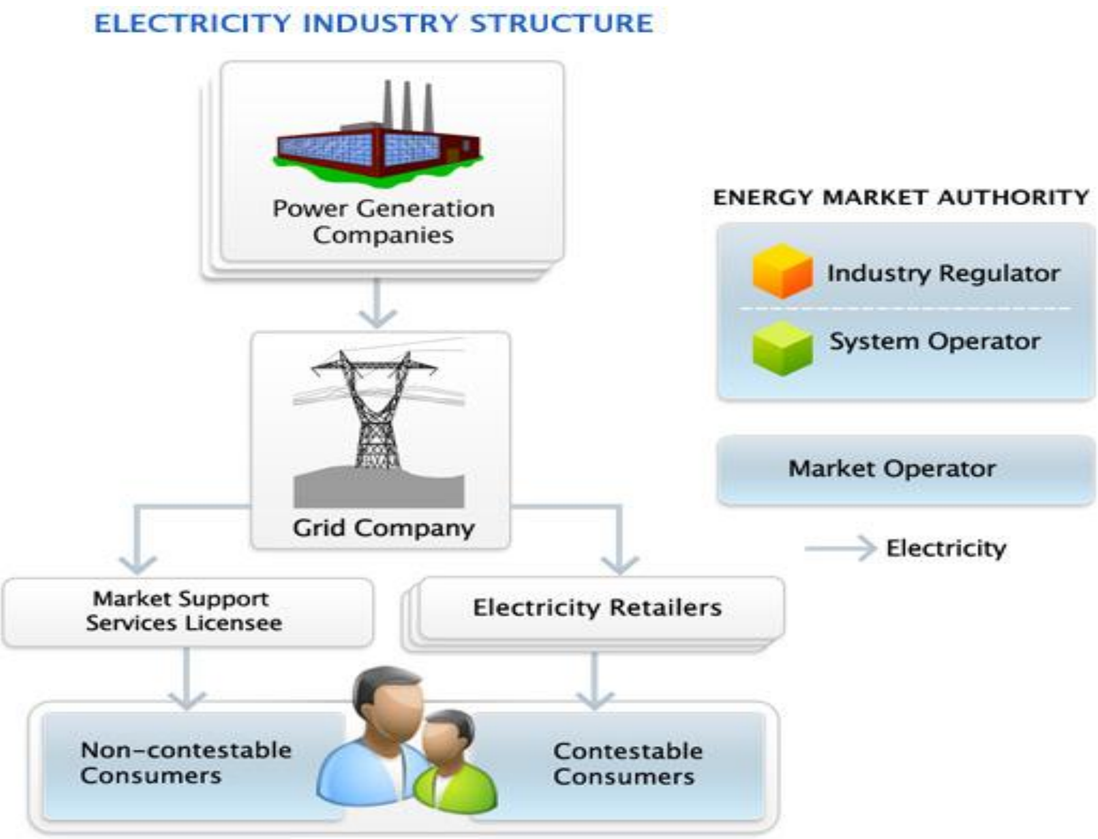


Figure 27: Structure of Singapore electricity industry

The electricity industry is categorised into contestable and non-contestable sectors. The structure of the Singapore electricity market is shown in the Figure 27.

The players in the contestable sector include:

- **Generation Licensees:** Are authorised to generate electricity and represent generating units with individual name-plate rating of 10MW or above. If connected to the electricity transmission system, the generating unit(s) must be registered with the Market Operator-Energy Market Company (EMC) and the generation licensees will have to compete to secure dispatch of their respective generating units in the National Electricity Market of Singapore (NEMS).

- **Electricity Retail Licensees;** Are authorised to retail electricity to contestable consumers. There are two types of electricity retailers: market participant retailers (MPRs) and non-market participant retailers (NMPRs). MPRs have to be registered with the Energy Market Company (EMC) to purchase electricity from the NEMS to sell to contestable consumers. NMPRs need not register with EMC to participate in the NEMS, since they will purchase electricity indirectly from the NEMS through the Market Support Services Licensee (MSSL).

- **Wholesaler (Generation) License:** Is required if a company owns generators with individual name-plate rating of 1MW or more but less than 10MW and the generator is connected to the power grid. For generating units with individual name-plate rating of less than 1MW that wish to be paid for the electricity it exports to the power grid, the generating units(s) must be registered with the Energy Market Company (EMC) and may have to compete to secure dispatch in the NEMS. If the total aggregate capacity of the generating units owned by the company in a single location exceeds 10MW, these generating units will have to bid to secure dispatch.

- **Wholesaler (Interruptible Load Service) License:** In the NEMS, consumers can offer to have their load interrupted during times of system supply shortage. Companies who either offer their own load to be interrupted, or provide services to other consumers interested in offering their load to be interrupted, are required to hold a Wholesaler (Interruptible Load) Licence issued by the Regulator - Energy Market Authority (EMA) .

The companies that operate in the non-contestable sector are natural monopolies and they are:

- **The Energy Market Authority (EMA):** is a statutory board which regulates the electricity and piped gas industries and district cooling services in designated areas, and is also responsible for ensuring the security, reliability and adequacy of electricity supply.
- **Energy Market Company:** Is the market company licensed by EMA to operate and administer Singapore's wholesale electricity market called the NEMS. As the Regulator and the Power System Operator, the EMA oversees the activities in both

the contestable and non-contestable sectors to ensure a competitive, secure and reliable electricity supply to consumers. EMC is jointly owned by EMA (with 51% shareholding), and M-co (The Marketplace Company) Pte Ltd (49%), a wholly-owned subsidiary of M-Co International Ltd from New Zealand. Besides operating and administering the NEMS, EMC also schedules generating units and settles accounts of market participants.

> **Transmission Company:** SP PowerAssets Ltd (SPPA) owns and manages the national electricity transmission system. SPPA has appointed SP PowerGrid Ltd (SPPG) as the agent to carry out the management and operation of all aspects of the transmission business. SP PowerGrid Ltd is licensed by the Energy Market Authority (EMA) as the transmission agent licensee. SPPG is responsible for ensuring the reliable supply of electricity to consumers and the secure operation of the power system. It controls the dispatch of facilities in the wholesale market (generators and customers that participate in the reserve markets) and coordinates outage and emergency planning and directs the operation of the Singapore High voltage transmission system under the terms of an operating agreement with SPPA the transmission licensee. SPPG provides updates to the EMC of: the status of the network; the loadings of each generation unit; and forecasts of demand. They then dispatch facilities in the market following the market produced co-optimised schedules.

> **Market Support Services Licensee**: SP Services Ltd, as the Market Support Services Licensee (MSSL), provides market support services such as retail settlement, meter reading and meter data management, customer transfer services for contestable consumers who switch from one electricity retailer to another and supply of electricity to non-contestable consumers. The MSSL also facilitates access to the National Electricity Market of Singapore by contestable consumers who have not appointed an electricity retailer. In addition to its market support services functions, SP Services Ltd also provides billing and payment collection of charges for use of the electricity transmission system on behalf of the Transmission Licensee.

End user participants are categorised as follows:

> **Non-Contestable Customers:** These are consumers with a total monthly consumption of below 10,000kWh. They buy their electricity from the MSSL at a regulated tariff.

> **Contestable Customers:** These are consumers with a total monthly consumption of 10,000kWh and above. They can buy their power from any of the licensed retailers or, at spot market price, by buying directly from the MSSL. The prices Contestable

Consumers pay to the licensed retailers are freely negotiable and not subject to regulatory controls.

5.1.1 Generation

There are 5 main active Generation Companies in Singapore. Each has available piped gas from one or more of three pipelines supplying the country. There are two gas pipelines from Indonesia (one from the West Natuna field and one from South Sumatra) and one gas pipeline from Malaysia. Approximately 80% of the nation's demand for electricity is provided from Combined Cycle Gas Generators. Currently, electricity generation is spread among three large players – Senoko Energy, Tuas Power and Power Seraya – and two smaller ones: Keppel Energy and Sembcorp. Tuas Power was acquired by China Huaneng Corporation. All five power entities have retail electricity subsidiaries and compete with one another in terms of the tariffs they offer to eligible consumers.

The Market Share of each generation company in Singapore is shown on the chart below:

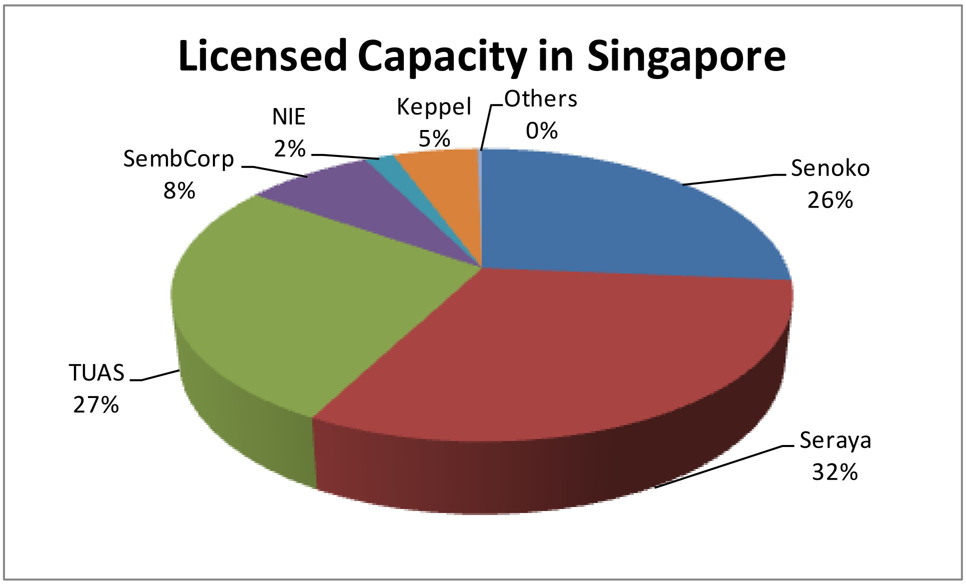


Figure 28: Licensed Capacity of each generation company (as of Sep 2011)

A full picture of the Generation Mix in Singapore can be seen in Table 7 below. The liberalisation of the power sector has opened up opportunities for newer players to come into the market. Island Power, which was acquired in 2009 by India's GMR Infrastructure, is now planning to start construction of an 800 MW gas-fired power plant on Jurong Island, home to the majority of Singapore's manufacturing and processing industries.

Table 7: Singapore Generation MixSep 2011 (Source: EMA)

	CCGT	Steam plant	OCGT	Others	Total

Senoko	1,945	500	105	55.4	**2,605.4**
Seraya	1,472	1,448	180	0	**3,100**
TUAS	1,470	1,200	0	0	**2,670**
SembCorp	785	0	0	0	**785**
NIE	0	0	0	179.8	**180**
Keppel	500	0	0	22	**522**
Others	0	0	0	29.6	**29.6**
Total	**6,172**	**3,148**	**285**	**286.8**	**9892**

5.1.2 Demand

Demand Shape

Demand for Electricity follows a similar pattern across the year. It is largely unaffected by seasonal variations as Singapore is located very close to the equator. Typical patterns for Singapore with max and min demand as recorded in August 2011 is presented in Figure 29:

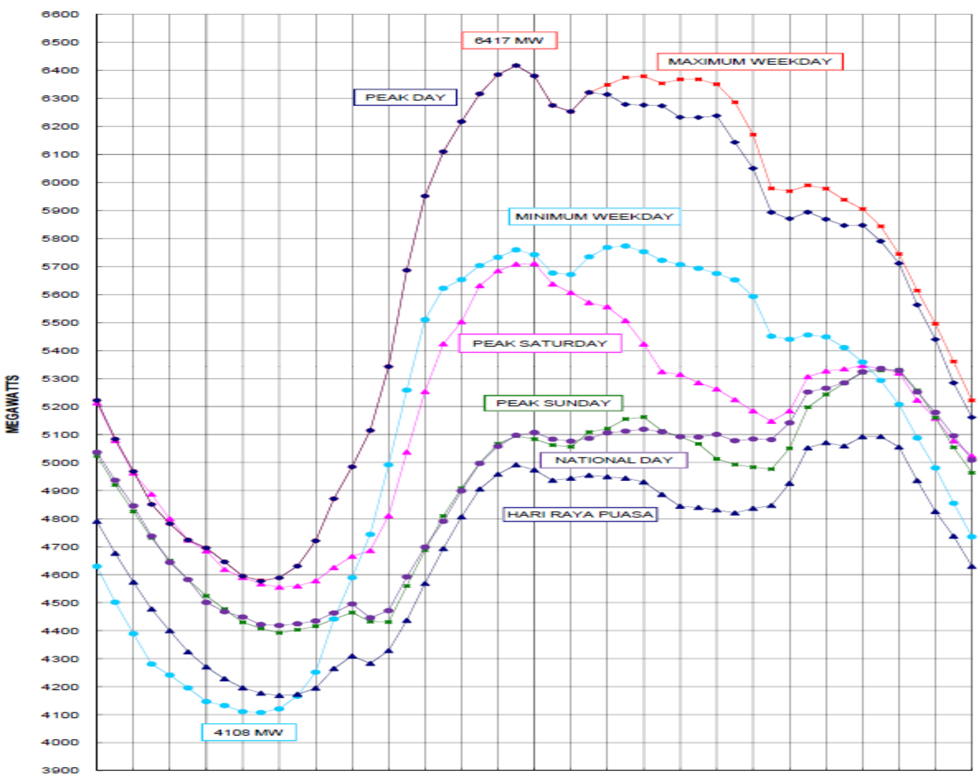


Figure 29: Max & Min Demand curve (August 2011)

Demand Growth

Over the past four decades, Singapore's electricity demand has been growing steadily at an average rate of 6% per annum and has increased 2.6 fold since 1990. Peak demand has also grown steadily until reduction in manufacturing and other economic activities caused a small contraction in electricity demand. Average annual demand growth over the coming 10 years is forecast to recover somewhat at around 4.5%. An illustration of annual progression over the past 12 months is shown in Figure 31.

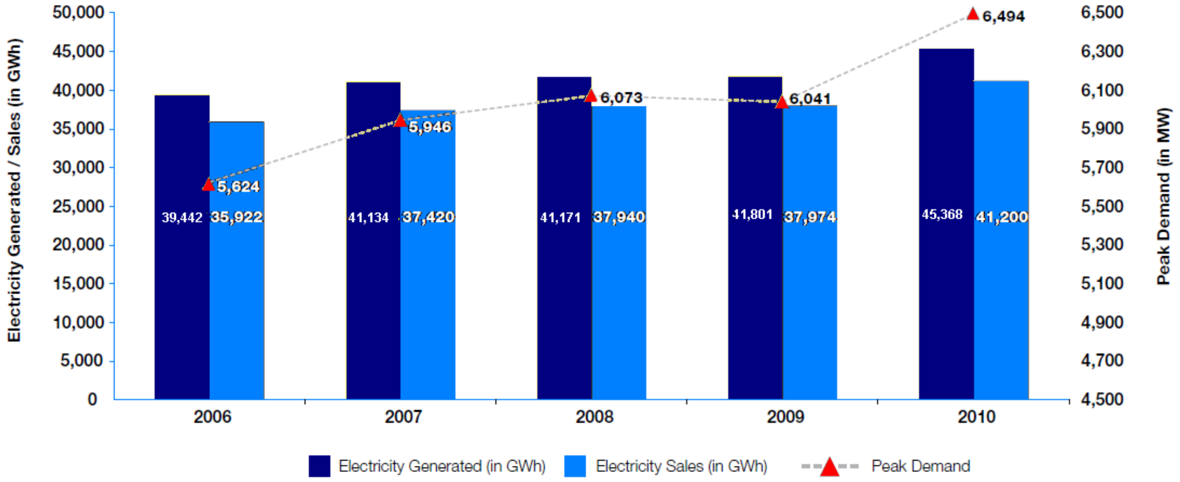


Figure 30: Electricity generated, sales and peak demand (source: EMA_Annual Report 2011

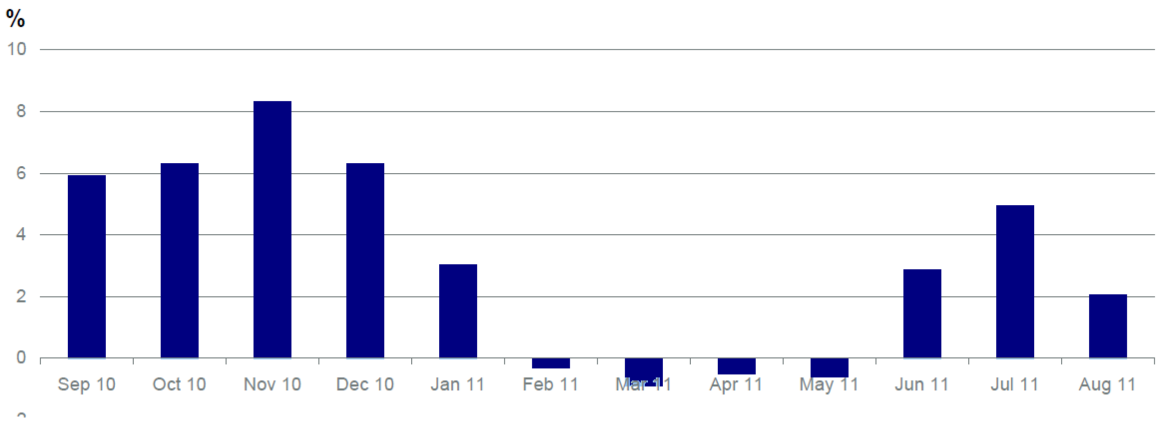


Figure 31: Year-on-year change of demand in Singapore (source: Energy Market Company)

Singapore has a total of 1.3 million customers connected. These Customers are divided between Manufacturing, Other Industries, and Domestic.

5.1.3 Network

The Singapore Power Network is owned by Singapore Power Assets Ltd (SPPA). SPPA is the sole provider of electricity Transmission and Distribution services in Singapore.

The Electricity Transmission and Distribution Networks of Singapore comprise:

> Transmission network at 400kV, 230kV and 66kV.

- Distribution network at 22kV, 6.6kV and 400V.

The Network Size is categorised by the following (NOTE: As Singapore is a City State all Transmission and Distribution lines are underground):

- Underground cable length: 29,800km
- No. of 400kV substations: 3
- No. of 230kV substations: 15
- No. of 66kV substations: 86
- No. of 22kV substations: 5099
- No. of 6.6kV substations: 4994

Total network asset value: S$7.4 billion (Approximately)

The Singapore Electricity System has an interconnection with Malaysia with a capacity of around 400MW. The Peninsular Malaysia-Singapore interconnector commissioned in 1985 between Singapore's Power Grid's Senko Power Station and Malaysia's Tenaga Nasional Berhad's Plentong substation in Southern Peninsular Malaysia. The interconnection has improved the resilience of the two power systems but as Malaysia presently has no electricity market, no trades are permissible through the interconnector. As such it is used only for bilateral network support.

There are no significant constraints on the Singapore Transmission Network. Added to this there is a very substantial reserve margin although 1,200MW of this is provided by two 600MW steam generation units at Tuas Power which seldom operate as they are relatively high cost.

5.2 Services Used by the TSO

The system services used by the Power Systems Operator in Singapore are:

Reserves - The three categories of reserve used in Singapore are:

- **Primary** - Primary reserve must be available within 1 Second and stay available until Secondary Reserve can be called into service.
- **Secondary** - Secondary reserve must be available within 30 Seconds and stay available until contingency reserve can be called into service.

- **Contingency** - Contingency reserve must be available within 10 Minutes and stay available until the PSO advises that it is not needed.

Regulation - Regulation is also referred to as Frequency Response. Regulation reserve represents the flexibility that Generators offer to the PSO to balance supply and demand in real time.

Reactive Power – Generators provide reactive support to the network when required.

Fast Start Capability - Fast start capability represents a form of reserve that can be provided in an emergency by starting up a generator. This was originally procured by the PSO in Singapore from Open Cycle Gas Turbine units owned by Senoko Power and Power Seraya. With the level of reserve margin currently available to the PSO Fast Start Capability is no longer procured today and so will not be discussed further in this section.

Black Start Capability - Generators that provide black start capability use small diesel generators located alongside larger combined cycle or steam units to generate enough power to start the larger unit without external supply.

5.2.1 Procurement of Services

The wholesale market in Singapore actually comprises two markets:

- The "real time market" or spot market for energy regulation and reserve;
- The "procurement market" for other system services.

In the spot market, buyers and sellers trade in energy, reserve and regulation through EMC. In the 'procurement market' the EMC procures by contract, on the behalf of the PSO, all of the system services other than reserve and regulation. The principal contracted system services that EMC may procure are:

- Reactive support and voltage control service;
- Black-start capability;
- Fast-start services;

These services are dealt with in more detail below:

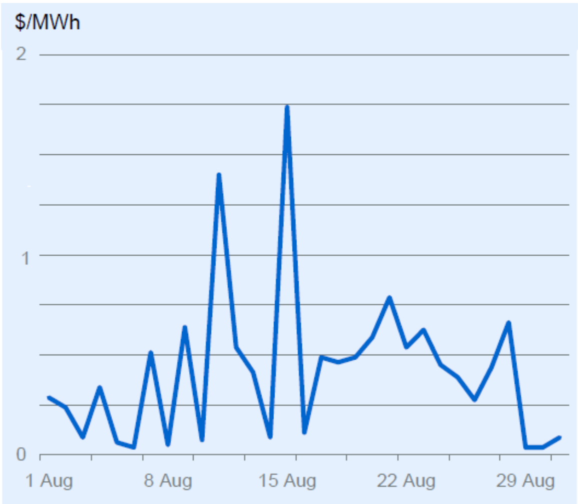
5.2.1.1 Reserves and Regulation

The NEMS schedules the provision of reserve and regulation simultaneously with the dispatch of energy based on offers received from market participants. Since generators that make plant available for the provision of regulation and reserve are forgoing energy production, the NEMS has reserve and regulation markets into which generators can offer capacity and for which they will be compensated. Each class of reserve can be offered to the market by Generators and Interruptible loads. Regulation can only be offered to the market by Generators.

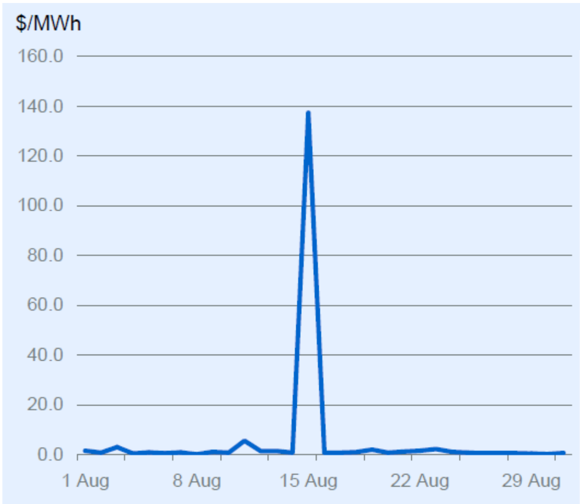
The offers comprise a five part stepped curve of offered availability and price. The offer must have lowest price first and increase prices as the amount of reserve offered in the category, or regulation increases.

The spot market co-optimises reserves and regulation with energy to form the lowest cost overall schedule for each ½ hour of each trading day. The reserve and regulation prices are calculated as the shadow price (the cost of the next increment of reserve or regulation that is needed in excess of the demand forecast). A single price is set for each class of reserve and for regulation in each ½ hour. All providers of reserves and regulation are paid the relevant price for each of the services.

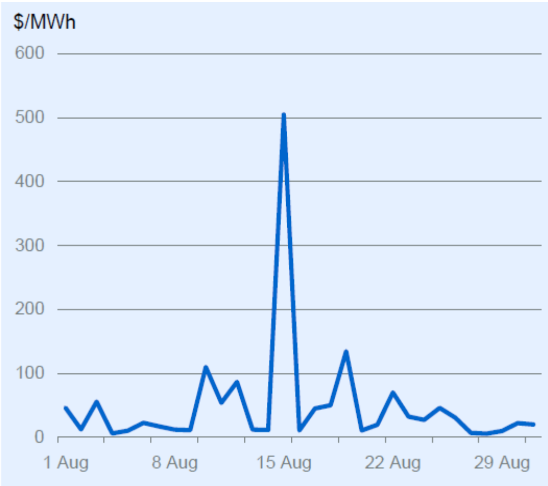
An example of prices for reserves and regulation for August 2011 is shown below:



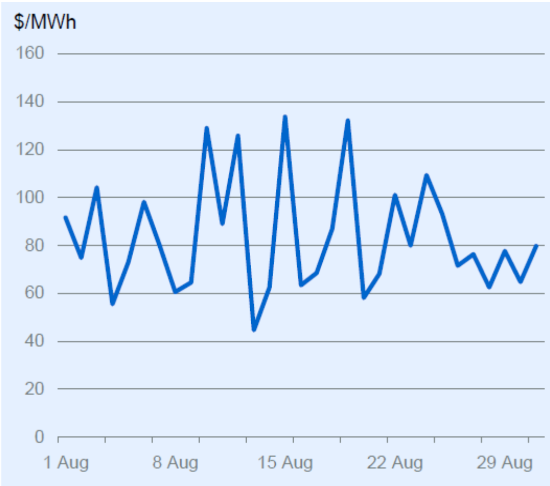
Primary Reserve Price ($/MWh)	
Monthly Average	0.33
Previous Month	0.53
Change	**-36.9%**
Max	16.32
Min	0.01



Secondary Reserve Price ($/MWh)	
Monthly Average	5.66
Previous Month	3.84
Change	**47.4%**
Max	1410.9399
Min	0.01



Contingency Reserve Price ($/MWh)	
Monthly Average	48.74
Previous Month	26.32
Change	**85.2%**
Max	3250
Min	0.01



Regulation Price ($/MWh)	
Monthly Average	83.25
Previous Month	75.79
Change	**9.8%**
Max	300
Min	0.01

Figure 32: Example of average daily prices for reserves and regulation for Aug 2011 (source: Energy market Company)

Reserve capacity is procured from the market to ensure that there is enough stand-by system capacity to cope with a single disruption. The formula for setting required Primary, Secondary and Contingency reserve capacity approximates to 1.5* the output scheduled from the generator with the highest loading on the system. This equates to circa 500MW of reserve. Average prices for Primary, Secondary and Contingency reserves in first three quarters of 2011 were 0.39$/MWh, 2.88$/MWh and 18.8$/MWh retrospectively. The graph below shows Monthly Reserve payments for the last 12 months:

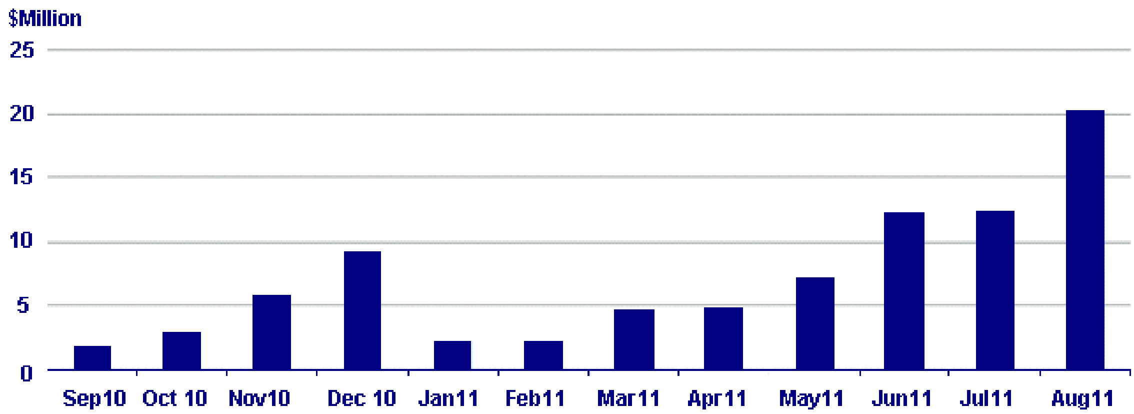


Figure 33: Monthly Reserve Payment for Last 12 Months (source: Energy Market Company)

Regulation required to balance the system typically sits at 100MW. The average price for regulation in first three quarters of 2011 was $64.92/MWH. The table below shows system services price statistics for (part of) 2011:

	Average Price ($/MWh)				Average Requirements (MW)			
	Primary Reserve	Secondary Reserve	Contingency Reserve	Regulation	Primary Reserve	Secondary Reserve	Contingency Reserve	Regulation
Jan	0.10	0.84	5.00	60.41	185	250	514	81
Feb	0.32	1.29	5.11	58.24	183	247	511	83
Mar	0.08	0.59	11.28	45.14	179	246	511	83
Apr	0.14	1.24	11.89	50.27	179	247	516	83
May	0.43	1.88	17.20	57.59	174	245	514	83
Jun	1.21	7.75	24.86	88.66	186	257	533	83
Jul	0.53	3.84	26.32	75.79	192	263	546	83
Aug	0.33	5.66	48.74	83.25	190	256	526	83
Sep	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-
Yearly	0.39	2.88	18.80	64.92	183	251	521	83
Q1	0.17	0.90	7.13	54.60	182	248	512	83
Q2	0.59	3.62	17.98	65.51	180	250	521	83
Q3	0.43	4.75	37.53	79.52	191	259	536	83
Q4	-	-	-	-	-	-	-	-

Figure 34: System services price statistics for (part of) 2011 (source: Energy Market Company)

5.2.1.2 Reactive Power

This is procured as a combination of an obligation, and a paid for service. Each generator is obliged to provide a given amount of Reactive Power as part of its license condition. Due to the capacitive nature of the Singapore System the need for procurement of Reactive Power is low. As such the obligation was sufficient to provide sufficient levels for 2011 and no additional power was procured.

When there is a need to procure Reactive Power (were that situation to change) then this is carried out by the Market Operator (EMC) on behalf of the System Operator in a competitive auction. If prices are not offered at competitive levels by the generators for this service then administered prices are set and contracts struck based on these.

5.2.1.3 Black Start Capability

This is procured in an annual auction run by the Market Operator on behalf of the Power System Operator. EMC can procure system services contracts for a period not exceeding 1 year. In consultation with the PSO, EMC procured 68.848MW of black-start capability services for period 1 Apr 2011 to 31 Mar 2012 at a total price of S$10.150 Million. Once again if the services were not offered by the generators competitively they would be procured at administered prices.

5.2.2 Incentives for Providers and the TSO

5.2.2.1 Ensuring adequate provision of system services

Adequate capacity to provide system services is provided for in the Generation License.

Ensuring available capacity is offered to the market is covered by means of emergency powers afforded to the PSO. If adequate capacity for any form of system services is not made available by participants then the PSO may command participants to provide sufficient services in which case these will not be paid for.

5.2.2.2 Incentives for Providers

Providers of system services are paid either at a market rate, or a rate that is more than sufficient to cover their costs depending on whether the services are directly sourced or traded in the spot market. In this regard providers are obliged to maintain the capability to provide their share of system services in relation to their generation licenses.

The Spot market traded services of Reserve provides revenue to the Generators and offsets the risk of a high spot price for Reserve occurring with consequent impact on reserve recharging.

The Spot market traded Regulation service provides profit to the generator and if providers do not offer enough of any specified service the rules allow the PSO to require service provision at zero cost. In this way the combination of Obligations and Market incentives provides adequate system services to the Singapore Market at all times.

5.2.2.3 Incentives for the Power System Operator

The Power System Operator is a division of the Regulators Office (EMA). The PSO is obliged to follow Market Produced Schedules. If the PSO dispatches services, or indeed energy, differently to the provisions of the market schedule then participants in the market can raise claims on the PSO. These claims may result in compensation payments being made by the PSO to the participant or participants concerned.

5.2.3 Cost Recovery

5.2.3.1 Reserves

The Singapore Market operates a “Causer Pays” principle where reserves are held to cope with the largest expected contingency event on the system. This is considered to be the loss of a single generating unit (that being the one that is supplying most energy to the system at the time). Generators are therefore re-charged the cost of reserves.

Generators are also ranked in order of highest to lowest load in each ½ hour. For each ½ hour a reserve cost allocation is calculated for each generator with the highest loaded generator carrying the largest proportion of the cost, and the least loaded carrying the least. The total cost of all reserves provided in each ½ hour is recovered from each reserve provider for each of its generation units:

Charge = Calculated Reserve Proportion * Total Cost of Reserves

5.2.3.2 Regulation

The cost of regulation is recovered from generators and consumers. The total cost of regulation in each ½ hour is calculated by dividing the cost by the total energy supplied in the ½ hour to arrive at a rate in S$/MWh. Generators are then charged that rate for the first 5MW of their generation from each generating unit. The remaining cost is charged to consumers/retailers as a regulation charge (AFP) in proportion to their consumption.

5.2.3.3 Reactive Power

Consumers are charged for reactive power only if they connect to the transmission network and only if they consume significant quantities of reactive power. This does not constitute a significant issue in the capacitive networks of Singapore and so its relevance is therefore minor.

5.2.3.4 Black Start

The cost of Black Start is recovered from consumers as a Monthly Energy Uplift Charge. The expected cost of black start provision for the month is divided by the forecast consumption for the month to arrive at a rate in S$/MWh. This rate is then charged to all consumers/retailers as an energy uplift charge (MEUC). At the end of each calendar month, EMC calculates the Monthly Energy Uplift Charge (MEUC) for the following calendar month and recovers the cost from the demand side volums (MWh). This charge, levied on retailers, covers the following potential payments and refunds each month:

- The cost of procuring contracted system services (e.g., black-start services) and related costs;
- Compensation claims and refunds;
- Financial penalties and refunds; and
- The estimated monthly energy uplift shortfall to be recovered and/or deducted in the following calendar month.

5.2.4 Evolution of Services

The provision of system services has changed from the original Singapore Power Pool methodology to the LMP market of today. In the Power Pool that operated from 1998 energy and reserves were the only commodities traded in the market. These were further limited to contingency reserve as all other services were, at that time, procured under contract to the PSO.

With the introduction of the NEM in 2003 Reserve trading has been included in the spot market with resulting reductions in the overall cost of reserve provision.

With the introduction of the NEM, regulation trading of this service in the spot market was seen to be a reasonable procurement approach until late last year when high prices resulted in an investigation as to whether this is the most appropriate means of provision of this service.

5.2.5 Compliance and Performance Monitoring

Ancillary services may be provided to the SO and the EMC only by registered facilities. In order to register each prospective ancillary service the provider needs to pass a number of tests for the applicable service as set out in the Singapore Electricity Market rules-Appendix 5A. The SO uses such a test not only to ensure performance of the new entrants but also to ensure already registered facilities continue to meet the requirements for registration to provide the applicable ancillary services.

Failure to pass a test will have as a consequence removal of the provider from the provider register until the provider can demonstrate that the registered facility can fulfil the necessary requirement as stated in Singapore Electricity Market rules. In addition, the Regulator or the SO may require compensation payment in relation to the applicable ancillary service during any period prior to the test, if the test results and other relevant information available indicate that the applicable ancillary service was not provided during that period.

The Regulator promotes self-regulation and encourages participants to act in accordance with their licence obligation and legal requirements. Where these compliance approaches fail, compliance enforcement mechanisms may be used. Further, the Regulator may impose 'other sanctions as permitted by the market rules or any applicable ancillary service contract'.[10]

5.2.6 Future Developments

Procurement of system services in the Singapore NEM is generally seen as successful. The only service that is brought into question is that of Regulation. There is a possibility that the way this will be procured will change in future. This is at present the subject of a pending

[10] Singapore Electricity Market Rules-Chapter 5

investigation into recent high Regulation prices where the initial outcome has yet to be published.

5.3 Summary and Implications

Singapore is an isolated system with a high single fuel dependency (gas) which explains its very high plant margin.

Arrangements as adopted in 2003 are very much in line with the New Zealand/Australia model including the integration of the energy market with regulation and reserve, which does not necessarily fit well with plant mix.

Reactive Power is not a material issue in Singapore due to high co-location of generation and demand but also a small geographic size of the network.

Despite 6 generation competitors, there is some suggestion of price collusion leading to unduly high regulation prices. Consequently although the absolute size of System Service costs are relatively low and the Regulator's approach is typically light touch; regulation costs are being investigated and as a result the market arrangements for regulation may be revised.

Singapore is as a country is probably the most similar to the SEM in terms of market size. However, with a heavy reliance on gas and no wind or coal generation, the plant mix in Singapore is not comparable to Ireland. Three important differences are the lack of any interconnection[11], the low requirements for reactive power and the high plant margin that exists in Singapore.

In summary, any review of potential lessons from the Singapore context for the application of system services in Ireland should carefully consider the small size of the island (and thus relative reduction in network issues) and the very high plant margin.

[11] No trades are allowed through the interconnector and it is only used for bilateral network support. No ancillary services can be procured via this interconnector.

6. Cyprus

6.1 Introduction and market overview

Cyprus operates under the provisions of the EU Directive, for 'Small Isolated Systems'. In 2004 the Cyprus Energy Regulatory Authority (CERA) was established by virtue of the Law on Regulating the Electricity Market of 2003 N.122(I)/2003, for harmonisation purposes with the Aquis Communitaire.

The establishment of CERA and the appointment of the Transmission System Operator (TSO) during 2004 constitute two very important events in the field of Energy provision, an area that prior to the entry of Cyprus in the European Union (EU), was run as a utility monopoly.

One of the urgent priorities of CERA was the opening of the Electricity Market. This was achieved with 35% of the market liberalised with effect from 1st May 2004. Further liberalisation took effect from 1st January 2009 when the market was opened to all non domestic consumers who from that date were free to select their supplier of choice. However, limited competition exists as due to market size and opportunity, independent supply companies have been slow to take up the challenge. As from 1st of January 2014 the market will be fully liberalised as the ultimate long term target is for all consumers to exercise the freedom to choose their supplier.

Table 8: Electricity Market Opening Table (Source: CERA)

Year	Market Opening (%)
1995	0
1997	0
2003	0
2004	35
2005	35
2006	35
2007	35
2008	35
2009	67
2010	67

2011	67
2012	67
2013	67
2014	100

In accordance with

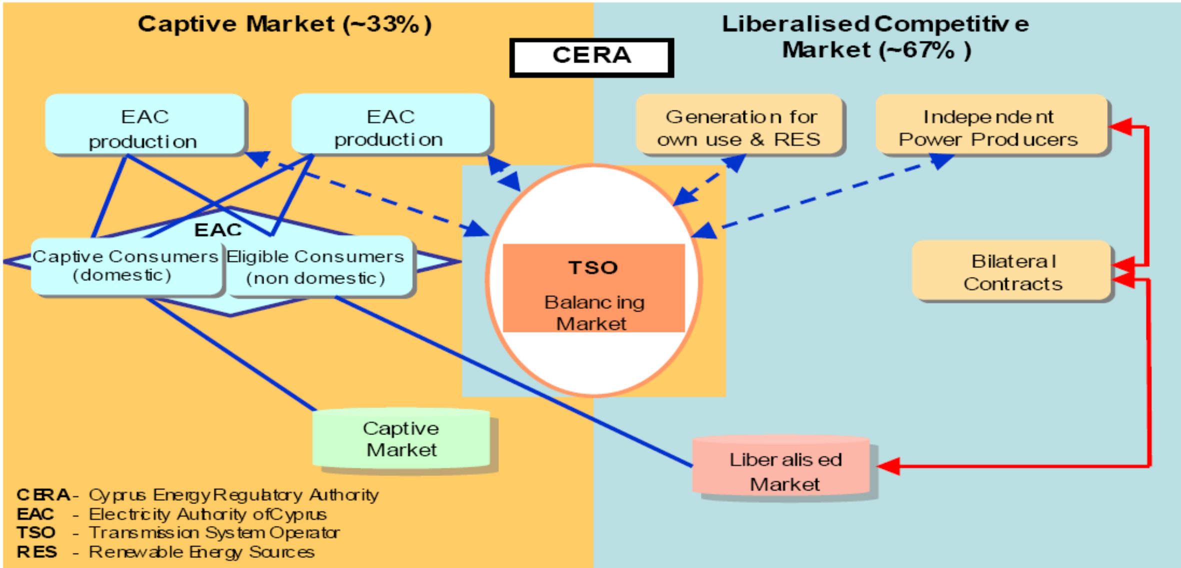


Figure 35 below it can be seen that the market is characterised by the following[12]:

- Market Regulation: CERA (with almost full authority).
- System & Market Operation: TSO (independent in legal and management terms).
- Basic Trading Arrangement: Bilateral Agreements.
- Balancing Market: 2% to 3% of energy traded through TSO.
- Captive Market: EAC, ~33% (domestic consumers only).
- Eligible Market: ~67% (all non domestic consumers).
- Competition in generation: EAC, IPPs, RES and Producers for Own Use.

[12] National Report CERA: Report to the European Commission in line with the Electricity and Gas Directives for the period July 2009 to July 2010

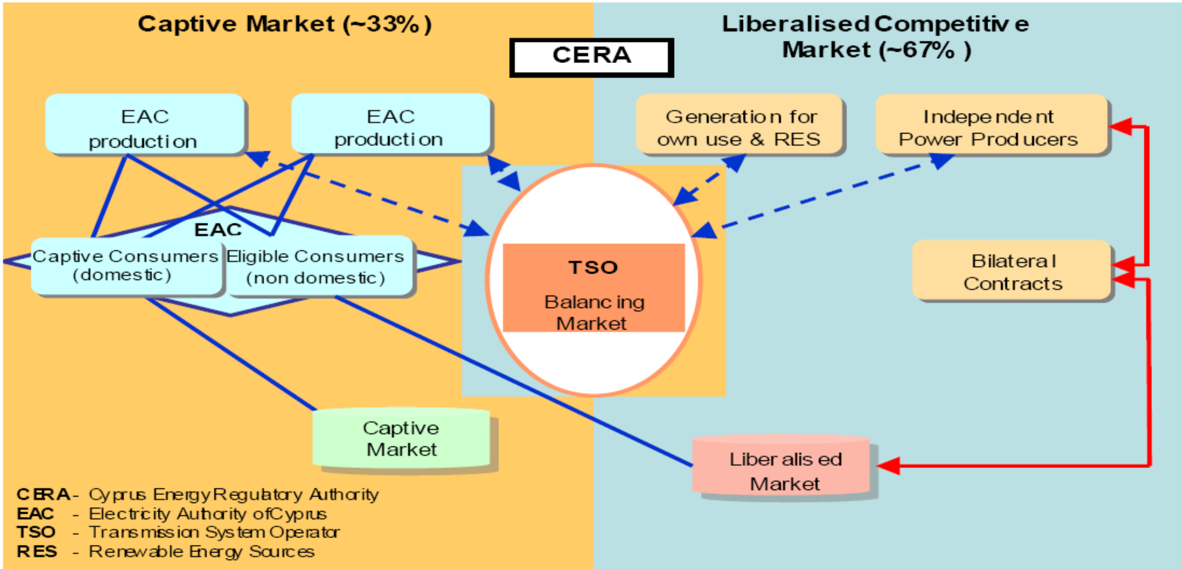


Figure 35: Cyprus Electricity Market Model (Source: National Report CERA)

Following the finalisation and approval of the Electricity Trading and Settlement Rules (Market Rules) in January 2009, CERA focused its efforts on resolving all pending issues related to market operation, including:

> The charge for the use of the Transmission and Distribution System, the relevant operating cost of the TSO, as well as the charge of the system services; and

> Methodologies related to the calculation of the capacity reserves and system services.

The above decisions also served to facilitate the further unbundling of the EAC accounts in order to establish the actual cost of all the services rendered by EAC, the vertically integrated electricity undertaking, minimising the possibility of cross-subsidisation between its activities and resulting in the goal of eventually lowering of the delivery price of electricity to end users.

6.1.1 Generation

Only one generator (EAC) is operating in Cyprus covering all the needs of the country. Generation is currently provided by three large power stations owned by EAC. The installed generating capacity is 1438 MW (July 2010) by the generating plants of EAC plus 26.63 MW by the independent producers for their own use and ~140 MW from RES. In November 2011, there were 133.5 MW of wind capacity connected to the network, generating ~100 MWh of electricity.

6.1.2 Demand

The annual consumption was 4650 GWh for 2006, 4850 GWh for 2007, 5049 GWh for 2008 and 5133 GWh for 2009 with an expected annual growth of 5% over the medium term. A recorded maximum demand of 907 MW in July 2006, 1056 MW in July 2007, 1010 MW in August 2008 and 1103 MW in July 2009 occurred with a significant daytime cooling load lasting from 8am to 5pm. Winter load is typically a third of this with an evening peak at 8pm.

In 2010 the Power Maximum Demand recorded was on the 3rd of August 2010 and reached a level of 1148 MW, (vis -à-vis a Demand Forecast of 1105MW). The total Energy generated for the whole of the year was of the order of 5272 GWh (vis-à-vis a forecast of 5380 GWh). The load factor for the year was of the order of 0.52.

In recent years the average annual rate of increase in Power Maximum Demand was of the order of 7.09% and the average annual rate of increase in generated energy was of the order of 3.65%. The levels of annual maximum demand as well as the annual energy generated are expected to continue a similar increasing trend[13].

There are just over 700 Eligible Consumers and, with the exception of a few very large consumers (cement works and a desalination plant) the majority are hotels. There are 523,000 consumers in total in the Republic of Cyprus. At present, the only operational licensed Supplier is EAC.

6.1.3 Network

There are approximately 800 km of transmission line, predominantly overhead cables, operated at voltages between 132kV and 66kV. There are no significant transmission projects, general reinforcement to meet load growth being the only exception. There are approximately 17,000 km of distribution line, three quarters of which is pole mounted, operated at voltages between 11kV and 415/220V. There are no significant distribution projects apart from general low scale reinforcement and network extensions to meet the modest load growth.

The network was originally developed to cover the entire island of Cyprus. Following the Turkish invasion this has meant that there is still a degree of interconnection with the Turkish Republic of Northern Cyprus where it has been uneconomic to disconnect the two systems. For example in 2004, the volume of unbilled electricity supplied to the Turkish Republic of Northern Cyprus was 7.8GWh. There are no connections between the island of Cyprus and the mainland and no agreements in place for network support from the Turkish Republic of Northern Cyprus.

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[13] National Report CERA: Report to the European Commission in line with the Electricity and Gas Directives for the period July 2009 to July 2010

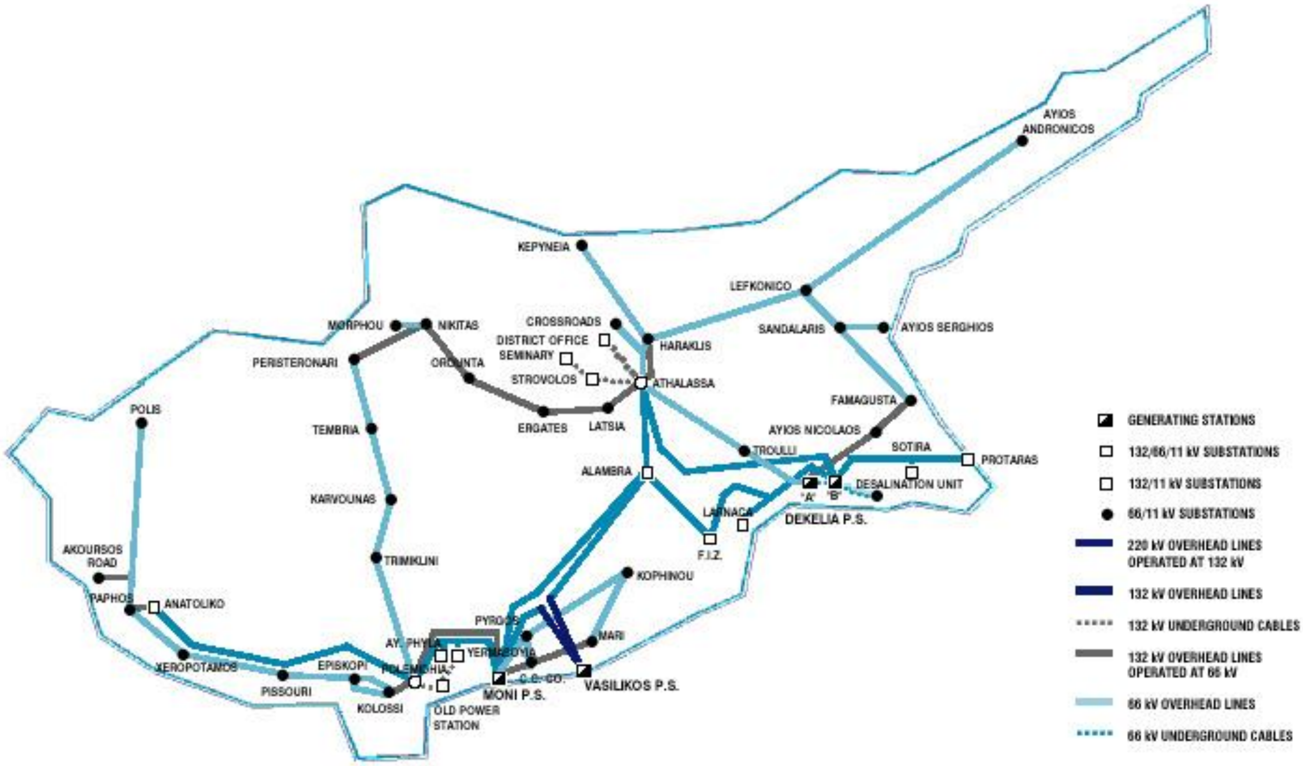

Figure 36: Electrical network in Cyprus

6.2 Services used by the TSO

Cyprus is currently operating a national electricity market that is totally dominated by EAC who is also the provider of system services throughout the island. In the future, market participants, with generating capacity exceeding 50MW will be able to participate in the market for system services.

Although demand side management is covered in the approved Transmission and Distribution Rules (TDR) there is not yet any active demand side response (DSR) participation.

According to the Transmission and Distribution Rules document that was placed into force in 2009 and was recently updated in June 2011, the TSO is responsible for procuring the following system services:

a) **Operating Reserve** – The additional MW Output required from Generation Units (or Demand reduction) which must be realisable in real time operation to contain and correct any potential Power System Frequency deviation to an acceptable level; this is composed of:

- **Primary Operating Reserve** - The additional increase in MW Output (and/or reduction in Demand) required at the frequency nadir, compared to the pre-incident output (or Demand) where the nadir occurs between 5 and 15 seconds after an event;

- **Secondary Operating Reserve** - The additional MW Output (and/or reduction in Demand) required compared to the pre-incident output (or Demand) which is fully available and sustainable over the period from 90 seconds to 5 minutes following an event; and

- **Tertiary Operating Reserve** - The additional MW Output (and/or reduction in Demand) required compared to the pre-incident output (or Demand), which is fully available and sustainable over the period from 5 minutes to 20 minutes following an event.

b) **Voltage Control** - Voltage Control is achieved under the responsibility of the Transmission System Operator through the following means:

- Use of System devices, notably control of autotransformers' tap changers, switching of lines and cables, use of electronic compensators or alternative means of reactive power production, switching of reactors and capacitors;

- Change of Unit Transformer tap positions; and

- Control of the Active Power generation of Units locally or centrally, as well as manually or automatically.

System Voltage Support Services are provided by generation units, that are not dispatchable nor contracted units, with regulated inactive power injection in order to assist System Voltage Control in the way established and prescribed by the Transmission System Operator;

c) **Replacement Reserve** - Replacement Reserve is the additional MW Output (and/or reduction in Demand) required compared to the pre-incident output (or Demand), which is fully available and sustainable over the period from 20 minutes to 4 hours following an Event;

d) **Contingency Reserve** - the margin of available Generation Capacity over forecast System Demand which is required in the period of 24 hours ahead down to real time, to cover against uncertainties in availability of Generation Capacity and against Demand forecast errors or variations;

e) **Frequency Response** - The automatic adjustment of Active Power output by a Generation Unit, initiated by free governor action in response to continuous minor fluctuations of Frequency on the Power System;

f) **Black Start** - Ability in respect of a Power Station, for at least one of its Dispatched Generation Units to start-up from Shutdown and to energise a part of the Transmission System and be Synchronised to the Transmission System upon instruction from the TSO; and

g) **Reactive Power** - The adjustment of Reactive Power output by a Generation Unit or other User's facility, in response to TSO dispatch instructions.

Frequency Response, Operating Reserve, Replacement Reserve and Contingency Reserve provide a reserve of active power available at increasing timescales that allow the TSO to accommodate forecast demand variations and Generating Unit unplanned outages. The provision of a Reactive Power system services allows the TSO to effect real time voltage control of the system.

6.2.1 Procurement of Services

Contracts for system services are bilateral contracts between the TSO and Participants and are settled through the Balancing Account under the terms agreed between the TSO and the Participant. There is no distinction made in any market documentation between mandatory service provision and commercial service provision. A system services agreement may cover individual services or a range of services as required.

Pricing of system services is subject to the approval of the Regulator and either party may apply to the Regulator for a judgement on the terms offered if there is a failure to agree terms. It should be noted that the law allows participants to recover costs "including reasonable profits" which is a cost plus approach.

A further restriction on Dominant Participants is that the TSO may require that prices offered should be in accordance with a Simulated Market Price Methodology. This methodology is agreed between the Regulator and the Dominant Participant and effectively caps the prices charged by the Dominant Participant. The Regulator identifies Dominant Participants in accordance with Cypriot competition law. It is expected that EAC will be identified as a Dominant Participant.

Payments by the TSO to system services providers are covered in the Trading and Settlement Rules (TSR) and are included in the monthly TSR invoicing process.

Contracts for Operating Reserve separate the fees paid for availability and usage by Settlement Period and these can vary by settlement period. An alternative mechanism for Operating Reserve was considered where the system services agreement would specify bid prices and levels in the Balancing Mechanism. Operating Reserve usage would be settled as part of Balancing Mechanism settlement. Payments for availability would be settled separately. However, it was decided to keep Operating Reserve provision separate from Balancing Market operation for clarity.

All other system services are based on a monthly tariff which is paid as part of the monthly TSR invoicing process.

It should be noted here that CERA and the TSO make every effort to encourage the use of renewable energy sources; all producers using RES are exempt from payment of these charges, i.e. the Use of System Charges (Transmission and Distribution) and Charges for system services, according to Article 16.7.3 of the Transmission and Distribution Rules.

6.2.2 Incentives for Providers and the TSO

Terms for the provision of system services are subject to bilateral negotiation (see below) and are set out in individual system services agreements. In this regard the TSR requires that participants with a total generation capacity greater then 50MW must offer a percentage of their generation capacity, excluding units based on renewable energy, in contracts for system services to, in the main, cover Operating Reserve margins. Other participants are free to offer capacity for system services but at present EAC will be the sole provider of system services and there is little if any demand side participation. The TSO is under no obligation to accept capacity if its requirements have already been met by other contracts at lower prices.

Furthermore, the TDR set out requirements for Generators and other Users to provide a capability for a number of system services except where this may threaten operator safety or to avoid damage to the plant. The TDR require a Generating Unit to be operated under the control of a Governor Control System in order to deliver Frequency Control except by prior agreement of the TSO or as the result of a Dispatch Instruction.

In order to provide Voltage Control all Generating Units are required to have Automatic Voltage Regulation allowing them to respond to a TSO Dispatch Instruction to provide Reactive Power. In addition, the TSO can require the TNO or DNO to perform tap changes or switch out Distribution lines, or occasionally transmission lines. Minimum requirements for all of these services are set out in the Connection Conditions of the TDR. Currently only EAC is covered by minimum Operating Reserve requirements as set out in the TDR. Variation to these minimum requirements may be provided for in relevant Connection Agreements.

Given the current state of the Generation stock, there is currently no express requirement for increasing the provision of Black Start capabilities. OCGTs at the large Power Stations were installed partly for peaking purposes and partly to provide Black Start capability. The TDR contains provisions for testing Black Start capability and basic information about initiating it in the event of a system emergency.

There is currently no incentive scheme for the TSO to reduce costs however the Law requires that the TSO operates and develops “an efficient, coordinated, safe, secure, reliable and economical transmission system”.

6.2.3 Compliance and Performance Monitoring

There is no information publicly available to show or demonstrate how participant compliance and performance monitoring is carried out or indeed what performance criteria exist to judge participants by. This is deemed to be a consequence of a general lack of market competition, and at this stage a lack of enthusiasm from potential participants to engage or partake in the market at this time.

6.2.4 Cost Recovery

In 2009 the Cyprus TSO proposed and CERA approved the Trading and Settlement Rules which, amongst other market documents allows the calculation and settlement of payments in respect of Energy and system services. The Balancing arrangements are also described in the latest version of the Transmission and Distribution Rules (2011) document.

Cost recovery by the TSO for system services is set out in the TSR and is either on a Settlement Period or Monthly basis as appropriate and agreed between the parties.

Operating Reserve costs are recovered on a Settlement Period basis. Recovery is from Suppliers in proportion to their total off take in the Settlement Period. These are billed as part of the single monthly run.

The remaining system services costs are recovered on a monthly basis, primarily for simplicity given the size of the market. Again, recovery is from Suppliers but in this case it is in proportion to their total monthly off take.

Modelling of system services costs has yielded costs that vary between 1€/MWh and 3€/MWh. Independent reviews of the modelling suggests that the actual figure may be towards the upper end of this range which is to be expected given, for example, the size of the largest generator loss (130MW) relative to demand. There are no figures in the public domain to verify these projections.

The TSO has calculated that the most cost efficient level of Primary Operating Reserve is 60MW with an annual fuel cost ranging from 8.5 million Euro to 12 million Euro. The estimates from the market regulator show that the balancing market covers 2-3% of energy traded trough the TSO.

The TSO suggests Primary Operating Reserve of 60MW, suitable to correct any potential Power System Frequency deviation to an acceptable level and to prevent any load interruption of more that 70MW in case the biggest generation unit goes out of operation.

6.2.5 Evolution of Services

The creation of an independent TSO responsible for procuring system services is the first evolutionary step away from an integrated, government controlled monopoly under which system services were internalised. Key milestones:

> The Electricity Market Law was agreed in 2003

> The TSO was fully operational in March 2005

> Electricity Market went live in May 2005

> First Version of the TSR and TDR were approved in 2005 (TSR only in principal)

> First year for operation of TDR (2006)

> Final version of the TSR was approved for operational use in 2009.

6.3 Summary and Implications

There is little to be learned by EirGrid from reviewing system services arrangements in Cyprus, due to:

> The scale of the market;

> The status and progress of the liberalisation process; and

> The associated competitive position regarding the lack of competition and the failure of new players to join the market.

As for all other markets studied, key system services capability is mandated by the technical network code, with remuneration made on a price availability basis.

System services were only introduced on a commercial basis in 2006. Thus there is no expected evolution of system services arrangements in the foreseeable future, especially given the small market and lack of competition in generation going forward.

Cyprus have chosen to follow an anglo-centric approach of addressing system services requirements separately from the wider energy market, probably due to market liberalisation advice being sourced largely from GB based consultants.

7. Spain

7.1 Introduction and market overview

The Spanish energy market is characterised by relatively higher energy intensity than the rest of Europe, by a high dependence on energy imports and by significant changes in the makeup of the energy system in the last few years. In this regard, the renewable energy industry exhibits significant growth driven by security and diversity of energy sources.

Before liberalisation, production of electricity in Spain was based on a system of “merit order” which pre-supposed that the regulator determined what installations had to function to supply demand in every time period. The definition of the Spanish electricity pool was established in Royal Decree in 1997 and the electricity market began to function from the 1st of January 1998. The market as a whole has been fully liberalised since January 2003; so, in effect, all Spanish customers (including households) have been free to choose their supplier for almost eight years. The market is structured as follows and as illustrated in Figure 37 below:

> A day-ahead market;

> Several intra-day markets that operate close to real time; and

> An ancillary services market.

Market players are permitted to enter into bilateral contracts but this method is not commonly used due to specific trading arrangements and certain financial barriers.

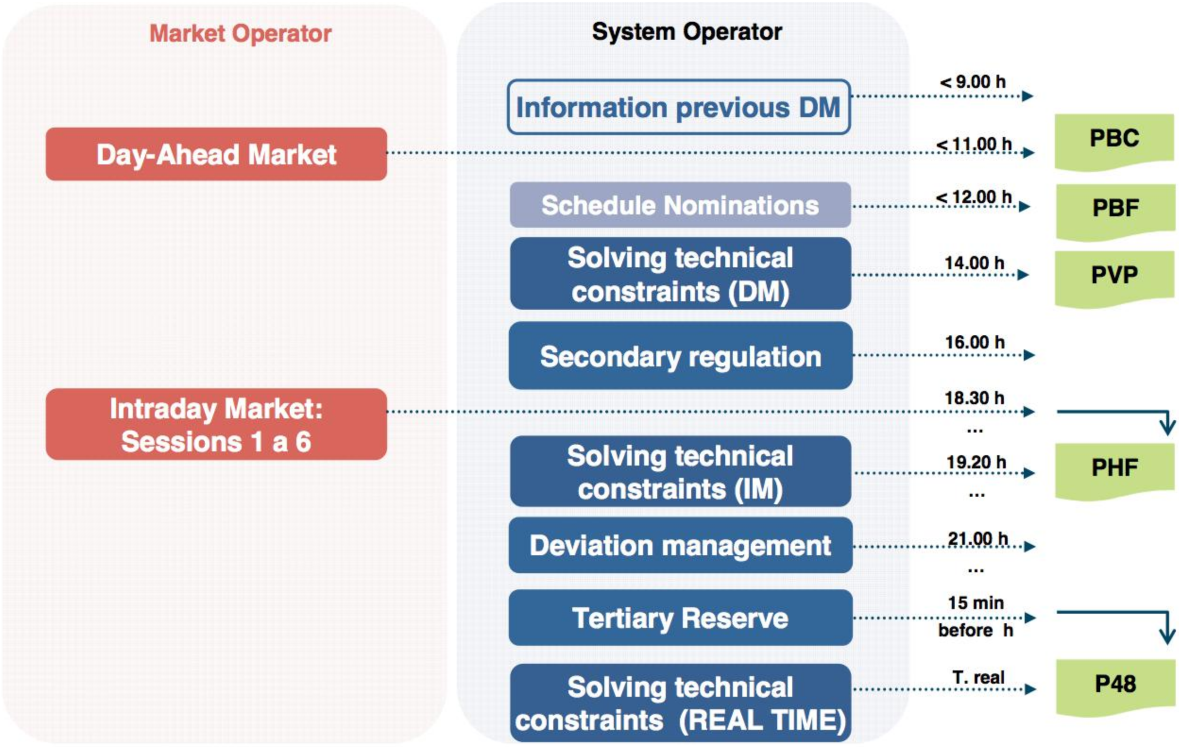

Figure 37: Spanish Market Scheduling process (Source: Red Electrica de Espana)

The introduction of the liberalised Spanish market has the prime objective of increasing the efficiency of the system and reducing delivery cost to the end customer. However, up until recently a limited number of new entrants had joined the market meaning competition was limited to only two companies dominating around 70% of total transactions, indicating that the market is still fairly immature and competition still has some way to go. With significant increase in new CCGT capacity natural gas companies are increasing their influence on the market, and electricity prices are becoming more and more correlated to natural gas forward prices.

Following liberalisation most transactions took place through the day-ahead market until the spring of 2006 when market rules were changed to shift more traded volumes to the adjustment markets. The management, efficient running and performance of market operations is generally overseen by the Regulator who retains responsibility for advising participants on the direction and progress of the liberalised arrangements; and a system operator, Red Eléctrica de España (REE), ensures technical feasibility in relation to both generation and transmission. The retail sector, despite its apparent deregulated nature, has not flourished as regulated tariffs have remained below market rates, making it difficult for new entrant suppliers to impact pre-liberalised supply methodologies. This applies to all customer sectors – domestic, commercial and industrial customers enjoy subsidised tariffs of one kind or another which will need to change radically if the nation is serious about shifting to a truly competitive framework for supply in the near future.

A separate wholesale market for forward contracts was created in July 2006 incorporating Spain and Portugal; this is known as the Iberian Electricity Market and it has its trading base in Portugal. Market prices are enhanced by fairly generous capacity payments which are intended to promote generation investment throughout the region.

7.1.1 Generation

Spain's generation mix has evolved significantly since 1990, when coal, oil, nuclear and hydro held the lion's share. The rapid development of combined-cycle gas turbines (CCGTs) (as well as wind and solar power) has diversified the generation mix, and it is expected that cleaner sources will continue to play a major role in the future. Increased availability of gas through imports from Algeria is likely to lead to an increasing share of gas fired generation in the electricity generating mix moving forward.

Spain is a peninsular system with weak interconnections. Essentially, electricity is produced by four vertically integrated incumbent firms: Endesa, Iberdrola, and two smaller competitors, Unión Fenosa, and Hidrocantábrico. Gas Natural, the most important gas producer in the country, has been the most active among a few new players in the Spanish market.

Generation facilities in Spain operate either under the Spanish 'ordinary' regime or the Spanish 'special' regime. It is a requirement that the electricity system must acquire all electricity offered by special regime generators, which consist of small or renewable energy facilities, at tariffs fixed by Royal Decree (or Order) that vary depending on the type of generation. Prices in this category are generally higher than Spanish market prices. Ordinary regime generators provide electricity at market prices to the Spanish pool and under bilateral contracts to qualified consumers and other suppliers at agreed prices. The generation mix is made up of hydro power, coal, oil-gas, nuclear, CCGTs, and renewable resources, of which wind takes on the most importance; it is worth noting that the Spanish solar and wind markets are one of the largest in Europe due to the favourable climate.

In the last decade renewable sources of energy have taken on a more prominent role in the market providing an increasing share of generation capacity. This has been greatly encouraged by government subsidies and feed-in tariff schemes. In order to monitor and better control such a huge increase of variable generation, Red Eléctrica introduced a new Control Centre for Renewable Energies (Cecre); an operational unit integrated into the Power Control Centre (Cecoel), which monitors and controls all wind farms of over 10 MW. In relation to this, Figure 38 and Figure 39 below show the generation mix and installed capacity for 2010 disaggregated by technology type.

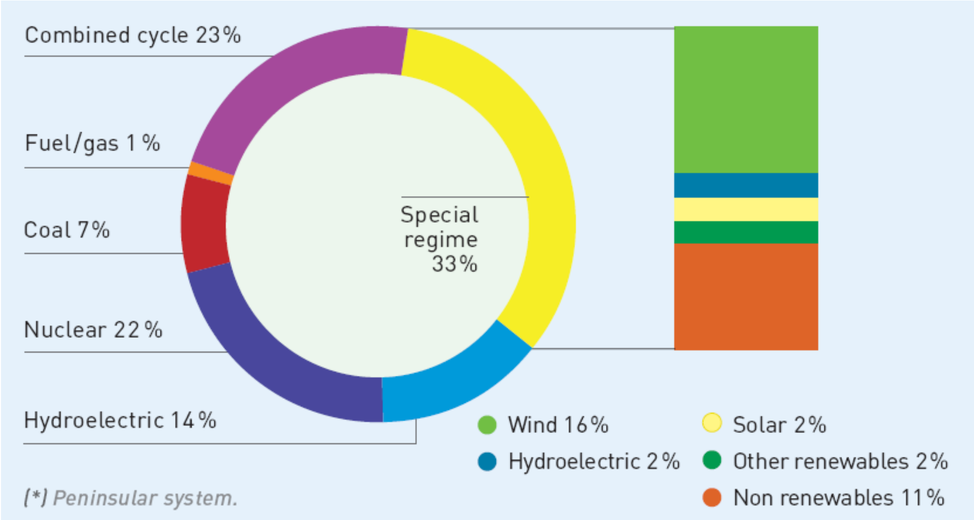

Figure 38: 2010 Demand Coverage of electrical energy (Source: Red Electrica de España)

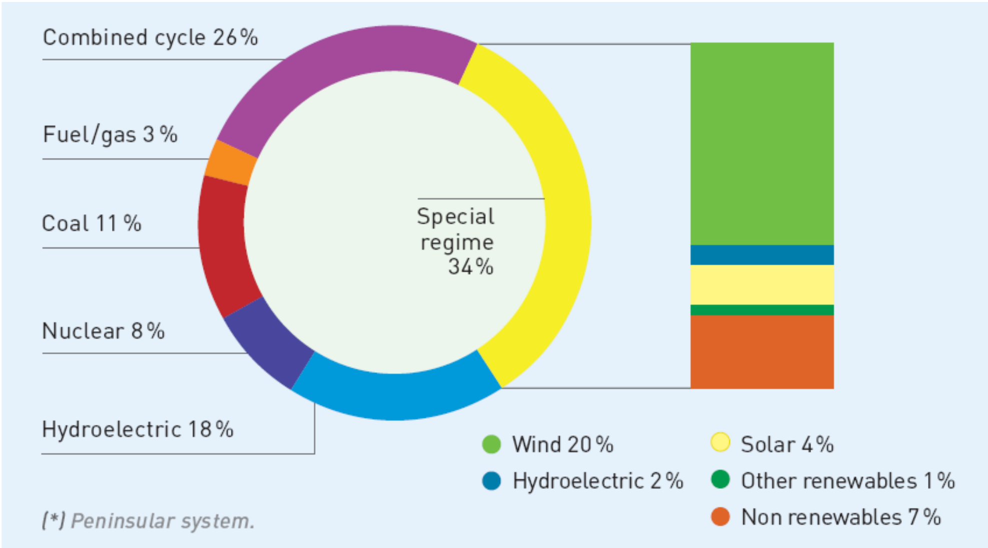

Figure 39: 2010 Installed capacity mix by technology in Spain (Source: Red Electrica de España)

Total installed generating capacity in Spain increased in 2010 by 3,717 MW to 97,447 MW, due mostly to new gas-fired generators, but also to wind and solar plants.

7.1.2 Demand

Spanish demand for electricity rose 2.9% in 2010 reaching 275.7 TWh per annum in which renewable energy boosted its share of usage by six percentage points to 35 percent, according to the national grid operator REE. The gain followed a recession-induced drop in demand of 4.8% in 2009. Wet weather caused hydroelectric output to rise by 59% in 2010, a factor which traders say has weighed heavily on wholesale power prices. Over the course of the last decade demand growth in Spain has been very high (over 30%), well above the EU average of 7%. The annual evolution of Spanish demand and GDP is shown in the figure below.

	Demand (GWh)	Δ Demand	Δ Demand (*) (by economic activity)	GDP
2006	255,022	3.1	4.1	3.9
2007	262,436	2.9	4.2	3.6
2008	265,206	1.1	0.7	0.9
2009	252,201	-4.9	-4.9	-3.7
2010	260,609	3.3	2.9	-0.1

(*) After factoring in the effects of seasonal and working patterns.

Figure 40: Annual evolution of Spanish peninsula demand and GDP (Source: Red Electrica de España)

Electricity demand in Spain typically peaks in winter, although the summer periods are registering new records, due in part to the wider take up of air conditioning. Over the course of an average day, the demand pattern is quite volatile, with demand typically peaking at 9:00pm. A peak demand of 44,122 MW was observed on the 11th January 2010 (895 GWh of energy), a similar peak to what was recorded in the previous year.

7.1.3 Network

Red Eléctrica de España is the manager of the transmission grid and, as such, acts as the sole transmission operator in the Spanish market. In 2010, Red Eléctrica carried out the acquisition of the extra peninsular assets (Balearic and Canary Islands), as well as those transmission assets on the peninsula that were the property of the legacy utility companies. This brought about the definitive consolidation of its position as the sole transmission company and electricity system operator for the entire Spanish jurisdiction. Red Eléctrica's peninsular transmission grid is composed of more than 38,000 kilometres of high voltage electricity lines and more than 4,500 circuit bays, and has more than 72,000 MVA of transformation capacity.

The transmission network in Spain is well developed and is designed to transfer power from northwest, west and northeast of the country where generation is located to two main demand centres in central and Northeast of the country. Another characteristic of Spanish network is limited interconnection with the rest of Europe. Total interconnection capacity is around 3% of total demand in Spain but work is underway to increase this with a new grid interconnection between Santa Llogaia, Girona, Spain, and Baixàs in Pyrénées-Orientales, France, which will double the transmission capacity between the two countries. A transmission network diagram is shown below.

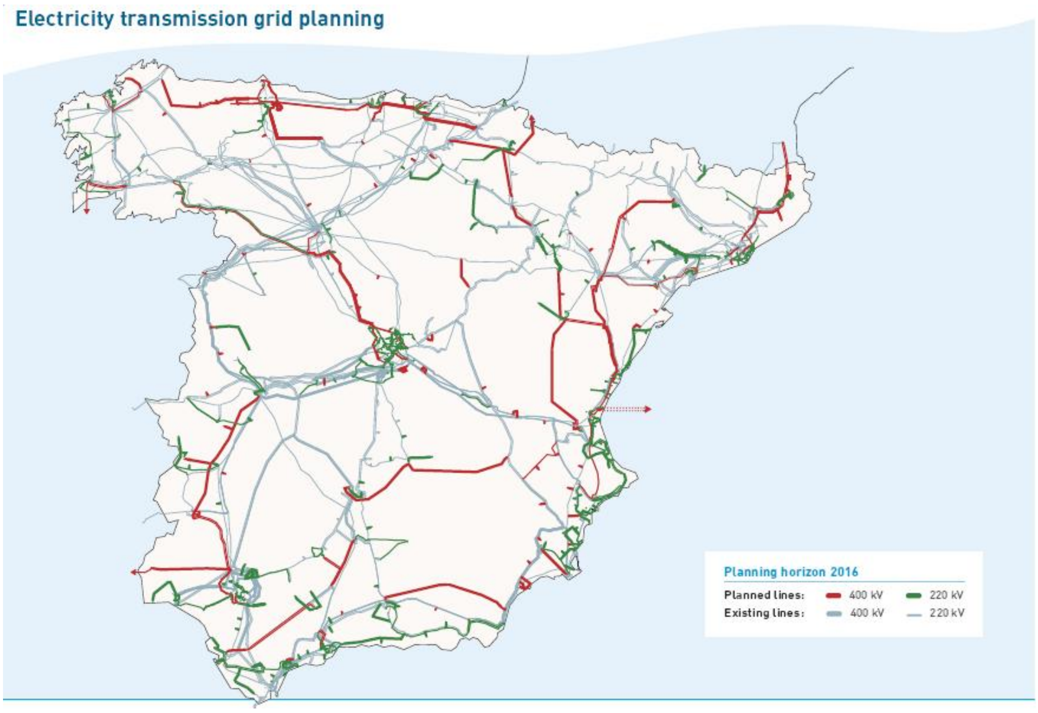

Figure 41: Transmission Network in Spain

7.2 Services used by the TSO

Spain follows the guidelines set by the European Network for Transmission System Operators for Electricity (ENTSO-E). ENTSO-E defines reserve in three categories: primary, secondary and tertiary control[14].

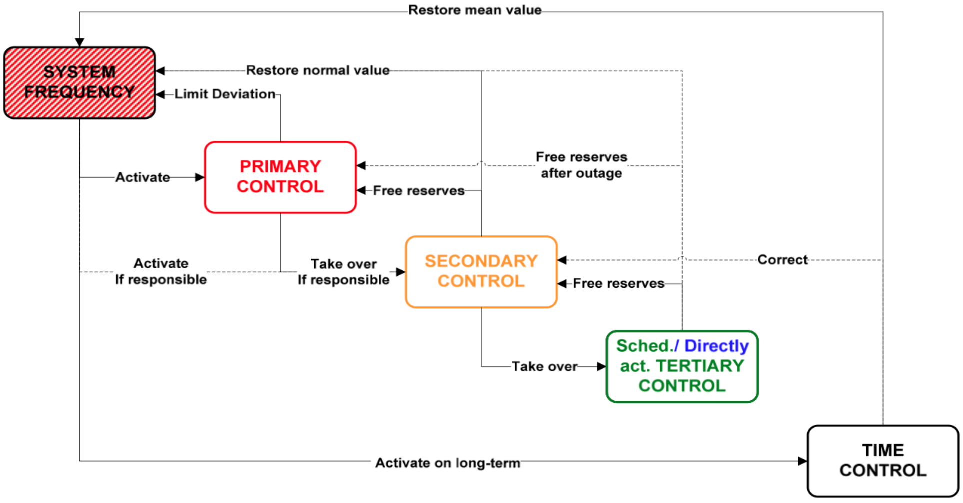

Figure 42: ENTSO-E frequency service control scheme

[14] Report: ENTSOE, UCTE Operational Handbook Policy 1, https://www.entsoe.eu/resources/publications/system-operations/operation-handbook/

Once the daily energy market is cleared, the system operator (SO) carries out congestion management analysis and modifies generation dispatch in order to ensure secure operation of the power system. Once network constraints have been cleared, the secondary reserve market (associated with Automatic Generation Control) is carried out. This market provides for day ahead upward and downward regulation reserves assigned to each generation company in the system scheduled to participate in automatic generation control.

Following this the intradaily markets are called. They are called six times a day (allows correction of infeasible schedules and/or schedule modifications) so that demand and generation agents can carry out adjustments before scheduled energy is delivered. It should be noted that in the Spanish electricity market only the first intradaily market is significant in terms of the amount of energy dealt. The rest of the markets are used in practice to solve operational issues such as infeasible running schedules.

The tertiary reserve market is intended to replace the secondary reserve in use, so it is only called and cleared if the secondary reserve is exhausted. Deviation management markets (also referred to as balancing markets) are only carried out if the SO predicts a significant energy deviation between generation and demand for the hours not covered by the intradaily markets. A generating company (GENCO) participating in the Spanish electricity market faces the issue of distributing its resources among these different markets.

7.2.1 Procurement of Services

The Spanish TSO is responsible for procuring the following Ancillary Services:

> **Primary Regulation:** This service is initiated by the set speed governors on generators and it can act automatically and in both directions as a result of a frequency deviation This service is delivered via action of speed regulators from generator units responding to changes in system frequency (<15s to 15 minutes).

> **Secondary Regulation:** Is defined as a centralised automatic control that adjusts the active power production of the generating units to restore the frequency and the interchanges with other systems to their target values following an imbalance. It is applied in time span from (≤100 s to 15 minutes).

> **Tertiary Regulation:** Manual changes in the dispatching and commitment of generating units and loads. This service is manual and is dispatched 15 minutes before the beginning of an operating hour, or within the hour if required. When dispatched, the energy must be sustainable for two hours if required. It is used to restore the primary and secondary frequency control reserves, to manage congestions in the transmission network, and to bring the frequency and the interchanges back to their target value.

- **Slow Reserve**: Running reserves of connected thermal units (30 min. to 4-5 hours).

- **Deviation Management:** Represents a rescheduling process intended to fix large differences (>300MWh) between generation and consumption for the period between intra-day market sessions. This service covers generation unavailability or differences in declared generation output.

- **Black Start:** Provision which includes generators that can start and supply energy to the transmission grid without any external source of supply.

- **Voltage Control:** System service, the aim of which is to guarantee suitable voltage control in the nodes of the transmission grid, so that the operation of the system meets the established security and reliability requirements, ensure that the energy supplied to the final consumers is in compliance with the required quality and that the generators can work in the established conditions for its normal operation.

The methodology used to access the services required by the TSO is outlined below:

Primary Control: Can be defined as the automatic increase or decrease of the output power of a generating unit due to frequency deviations and is based on its speed-droop characteristic. Primary control is mandatory for all generation outside of the special regime and there is no payment associated with this service. Generators with primary regulation operate with a reserve margin of 1.5%.[15]

Secondary Control: Is the only competitive capacity market developed to date. This is an ancillary service whose purpose is *"to maintain the balance between generation and demand, correcting the involuntary unintentional deviations, which occur in the real-time operation of exchanges with the European system, or the deviations in the system frequency with respect to the programmed values*"[16]. A portfolio of units categorised as a regulation zone provides this service. A regulation zone is a set of generating units under a single AGC. The control is automatic and has a hierarchical structure: the SO sends signals to each central dispatch unit in the market to request participation. The aim of secondary control (AGC-automatic generation control) is to bring the system frequency to its scheduled value. An additional objective of AGC is to maintain area interchanges at scheduled values. The Spanish power system, which is an area within the UCTE power system interconnected to the French, Portuguese and Moroccan systems, is charged with maintaining scheduled power interchange between Spain and France. Providers are remunerated in two ways: capacity (regulation band) and usage (energy).

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[15] -
, May 2009

[16] As defined by Red Electricity de España

Secondary control operation in Spain is based on the results of an hourly secondary reserve market. Generating units in the system submit their bids for upward and downward reserves (in MW) and their associated prices (€/MW) and reserve allocation is scheduled in economic merit order. The different bids are ordered by price and the lowest bids are accepted sequentially until the total reserve margin (in MW) required by the system is fully satisfied i.e. last accepted bid set the price.

Within the Spanish power system AGC is operated hierarchically. The area is divided into different zones (which correspond to generation companies), each of them with one or more generating units operating under AGC. The Spanish system operator computes an area control error (ACE) for the whole Spanish control area and distributes it among the different zones (every 4 seconds) using zone participation factors, thus obtaining the regulation requirement for each zone. These participation factors are calculated proportionally to the reserve assigned to each zone in the secondary reserve market. Each zone then distributes its regulation requirement among its regulating units based on technical and economic criteria using unit participation factors. The SO evaluates the dynamic response of each zone. Participants are penalised if their response does not comply with the established response criteria. The bid process described is represented in the diagram below.

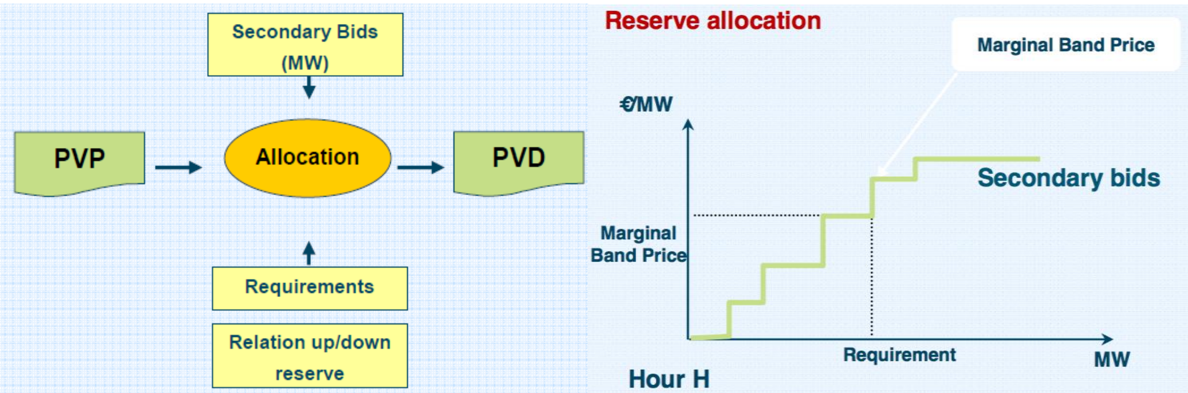

Figure 43: Secondary Regulation Process (Source: Red Electrica de España)

The Spanish SO procures as much as ±1,500 MW of secondary regulation which mainly includes fast-responsive hydropower generators.

Tertiary Control: Another active service is to the replacement of the secondary reserve in use, thus increasing the available reserve to the initial scheduled value. The tertiary reserve is defined as the maximum variation of power generation that a generation unit can carry out within a maximum of 15 minutes, and which can be maintained for at least 2 hours. It is mainly provided by spare capacity on already connected thermal and hydro units.

A tertiary reserve market has been established in Spain that is called and cleared only if the secondary reserve margins have been exhausted. Every day, after the secondary reserve market is cleared, the system operator defines a minimum amount of tertiary reserve that must be bid to the tertiary reserve market and made available in the event that the tertiary reserve market needs to be called. This minimum amount is computed hourly as the rated power of the largest unit within the system plus 2% of the forecast load for each hour.

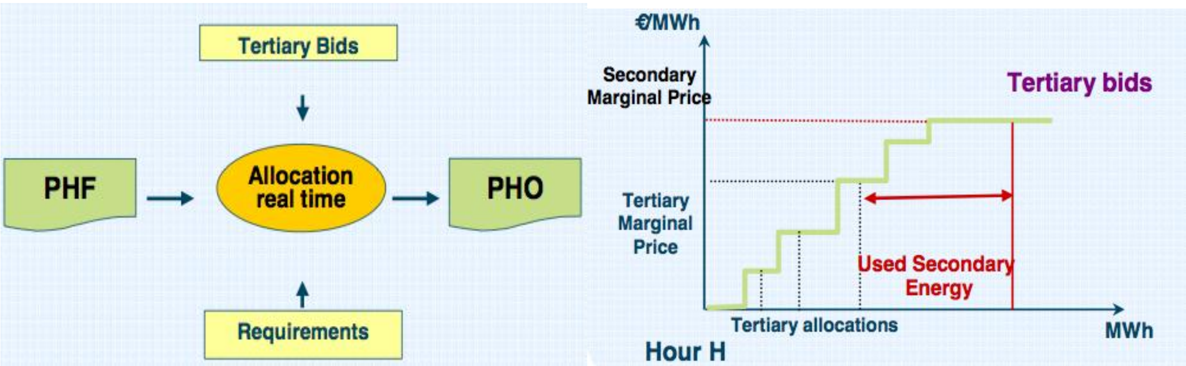

Figure 44: Tertiary Regulation Process (Source: Red Electrica de España)

Requirement and deployment of the tertiary reserve is affected by significant increase in variable generation connected to the Spanish network (Figure 44). Tertiary reserve requirements are expected increase with increasing penetration of wind and solar power generation in the power system. According to RD 661/2007 and Operational Procedure PO 3.2, if there are certain plants that can respond to a constraint need to be re-dispatched to solve a congestion issue the following order must be applied:

> Dispatch the Ordinary regime - in decreasing order of sensitivity;

> Non-renewable manageable special regime;

> Renewable manageable special regime;

> Non-renewable non-manageable special regime;

> Renewable non-manageable special regime.

From the following graph it can be seen that the system secondary reserve requirement has not yet been affected by an increase in variable generation on the system.

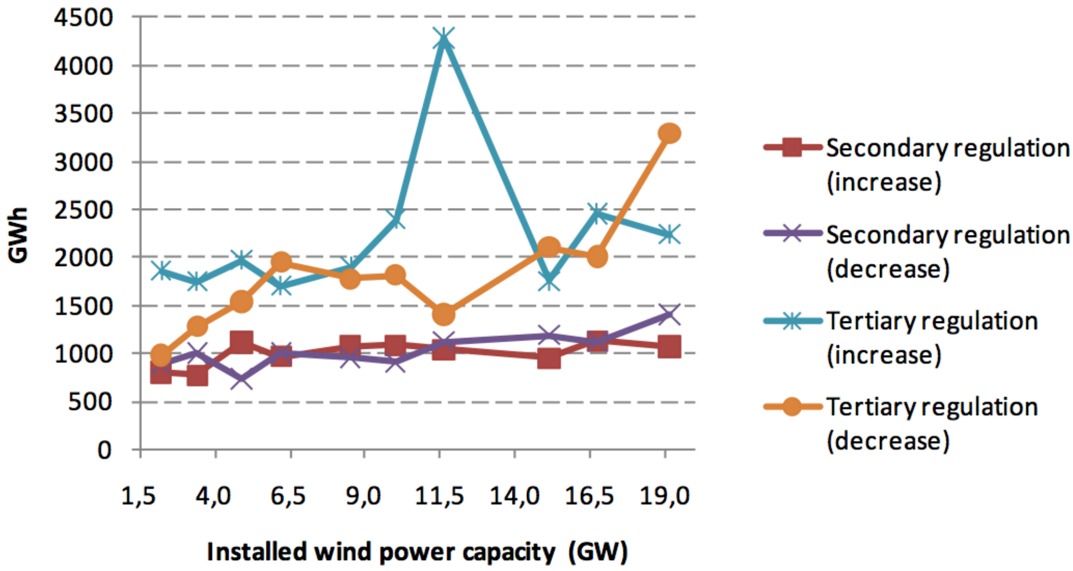

Figure 45: Evolution of secondary and tertiary regulation with the installed wind power capacity in Spain, 2000-2009

Deviations Management Market: Otherwise known as the balancing services market. In this case the system operator calls the service for the hours where the predicted demand imbalance is greater than 300MWh. Allocation of deviations management services is carried out in economic merit order – lowest cost first. Only generating units and pump storage units that deviate from their programmes are allowed to participate in this market.

Deviation management services also provide a connection between the tertiary regulation scheme and the intraday markets. The service is used by the SO as a flexible tool to solve the imbalances between generation and demand without jeopardising the availability of secondary and tertiary reserves.

Voltage Control: Is a service related to the provision of reactive power that has been designed in Spain to be partially obligatory, and partially subject to payment based on performance evaluation. The providers of the voltage control comprise generating units of over 30MW of rated power and qualified consumers (those who are allowed to buy energy in the wholesale electricity market) over 15MW having a direct connection to the transmission grid (which comprises 400 and 220 kV levels), the Spanish system operator as transmission system owner and the distribution companies. Qualifying consumers and distribution companies are the entities that mainly provide (demand side) voltage control services.

For the non-payable mandatory provision of reactive power (for each type of provider), generators must be capable of generating or absorbing a reactive power component equal to 15% of their maximum active power when operating at nominal voltage. When they are not at nominal voltage, non-linear percentage bands for maximum and minimum reactive generation are laid down. Figure 46 shows the mandatory figures for reactive generation and absorption for generators connected to the 400 kV transmission system. It shows that when the system reflects high voltages (over 1.05 pu), generators are not forced to provide reactive generation capacity. However, they must be capable of consuming a reactive component related to at least 30% of their maximum active power component. On the other hand when the 400 kV transmission grid reflects low voltages (under 0.95 pu), generators do not need to provide reactive absorption capacity, and they must be capable of providing at least 30% of their maximum active rating as reactive generation capacity

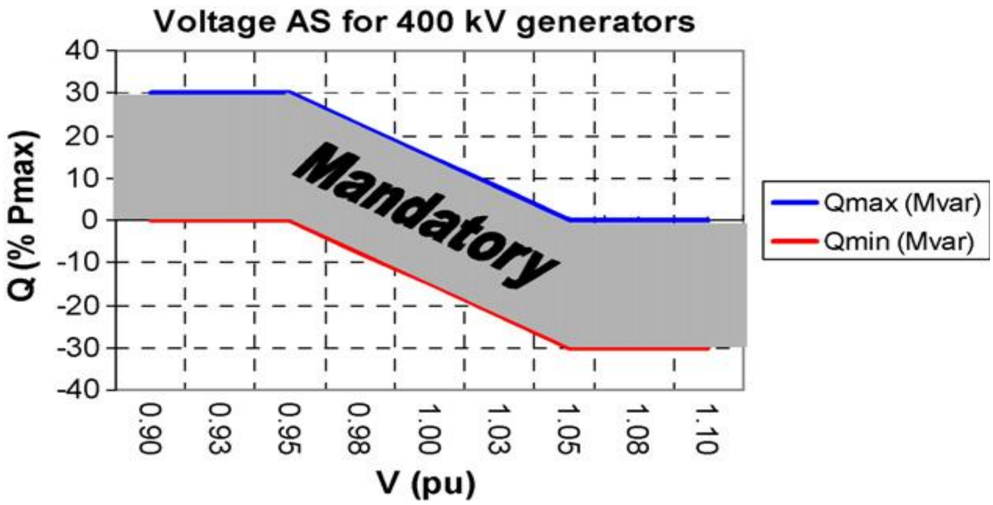

Figure 46: Mandatory bands for voltage control AS of generators (connected to the 400 kV grid)[17]

Transmission owners must contribute to voltage control using all available voltage control resources (transformer taps and shunt reactors and capacitors within the power system, and the opening of transmission lines). Qualified consumers and distribution companies must not generate reactive power to the transmission grid in valley hours; in peak hours they must not consume from the transmission grid more reactive power than 33% of their active load; for plateau hours they must neither generate reactive power to the transmission grid, nor consume reactive power more that 33% of their active load. Consumers have the option of participating in the provision of voltage control service as described earlier.

Black Start: Provision is not considered to be a remunerated service. The Spanish system operator has established an emergency energy restoration plan to be taken in case of blackout, agreed with the collaboration of all the utilities that operate in the Spanish power system. Nowadays, the transmission power network in Spain is well meshed. In this way, the risk of a total system failure is considered highly improbable. Therefore, it has not been necessary to design a remuneration regulation of the black-start ancillary service.

[17] 'An overview of ancillary services in Spain', Enrique Lobato Miguelez , Ignacio Egido Cortes, Luis Rouco Rodrıguez , Gerardo Lopez Camino, *School of Engineering of Universidad Pontifica Comillas, C/Alberto Aguilera, 23, 28015 Madrid, Spain*

7.2.2 Cost Recovery

Due to the difficulty in measuring the service provision and assessing performance quality, primary control has been defined as a mandatory non-remunerable system service: generating units must be capable of modifying 1.5% of their rated output in less than 15 seconds for frequency variations less than 0.1Hz, and linearly up to 30 seconds for frequency deviations up to 0.2Hz. A deadband is permissible but it must not exceed 0.01Hz.

Generators are the providers of secondary control services. Remuneration is made up of a capacity component from the secondary reserve market clearing price (€/MW, paid by demand proportionally to metered energy – except pumping consumption and exports) and an energy component (€/kWh, paid by generation and demand units which deviate from their programmes), where deviation from scheduled values (due to secondary control operation) is priced at the substituting tertiary energy price that would result if the tertiary reserve market were called. Penalties for non compliance with the agreed response criteria or for the lack of provision in support of the reserve regulation band (assigned in the reserve market during secondary control operation) are also taken into account to determine full and final participant remuneration. Tertiary reserve market bids are in the form of reserve capacity (in MW) and associated volume related energy prices (€/MWh). Only finally used tertiary energy is remunerated, i.e. the tertiary energy generated by units whose tertiary reserve has been deployed.

The services for adjusting the Spanish electricity system are managed by the Spanish system operator and include the processes for resolving the system's technical constraints, the provision of ancillary services and the management of deviations. In 2009 and 2010, the volume of overall energy deployed in these markets was 23,917 GWh and 28,215 GWh[18] respectively which accounted for 8.95% and 10.8 % of the total energy contracted in the Spanish electricity system. Cost of management of the Spanish network increased from €390.3m in 2009 to €593.8m in 2011. A split between the various types of system services is shown in Table 9 below. Day-ahead technical constraint solution processes and tertiary regulation were the most frequently called services and hence they represented the greatest energy requirement in relation to the provision of system services.

Table 9: System Services split (Source: Red Electrica de España)

GWh	2009		2010		% 10/09	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Technical Constraints	9,475	-707	12,509	-447	32%	-36.80%
Secondary regulation	1,072	-1,406	1,165	-1,724	8.70%	22.60%
Tertiary regulation	2,238	-3,287	2,726	-2,983	21.80%	-9.30%
Deviation management	1,253	-3,018	2,198	-2,675	75.40%	-11.40%

[18] RES report: The Spanish electricity system 2010

Constraints in real time	821	-640	887	-901	8%	40.80%
Total	**14,859**	**-9,058**	**19,485**	**-8,730**	**31.13%**	**-3.62%**

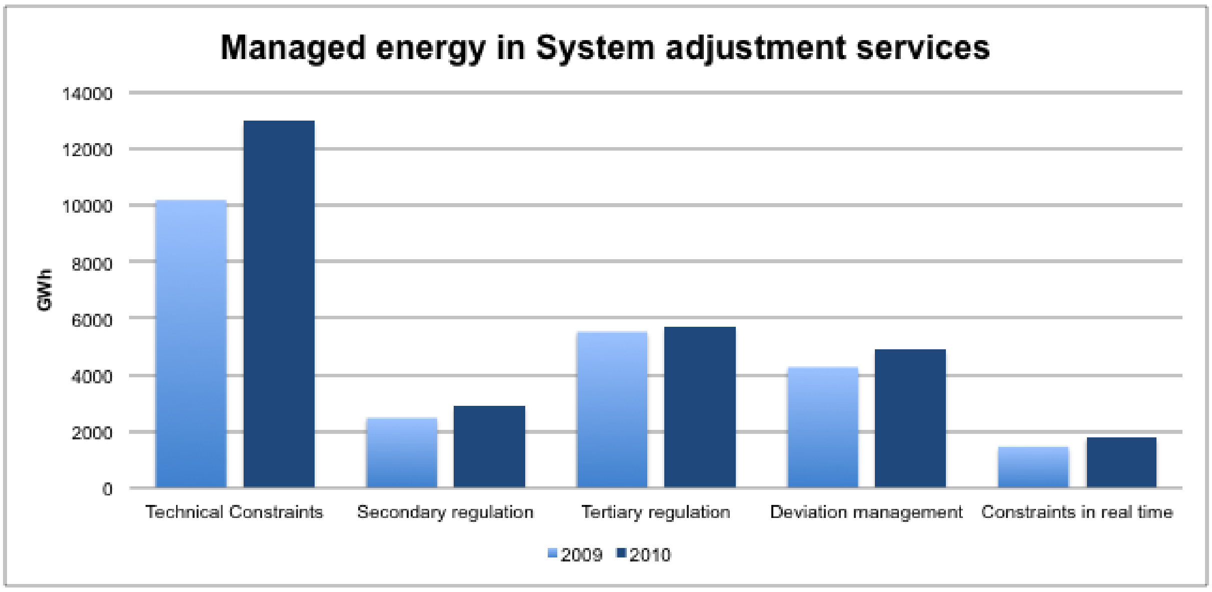

Figure 47: Managed energy in the system services (Source: Red Electrica de España)

A summary of the payment in relation to the provision of technical services based on information provided by the TSO is provided in the following illustration.

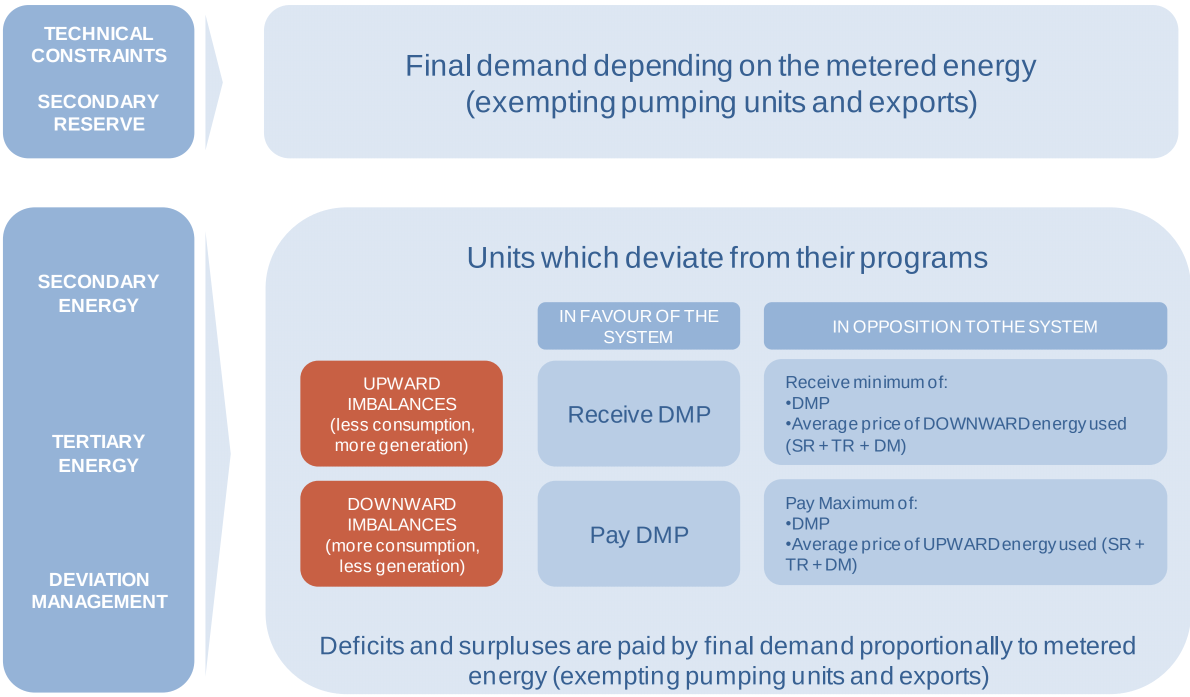

Figure 48: Payment of Technical Services (Source: Red Electrica de España)

7.2.3 Compliance and Performance Monitoring

Primary regulation is a non paid mandatory service for all of the participants outside of the special regime.

System service providers' performance and system compliance for secondary regulation is performed in pre-defined zones. The whole system is divided into different zones (which correspond to generation companies). The system operator evaluates the dynamic response of each zone and if its response does not comply with the established response criteria the whole zone is penalised. Secondary regulation remuneration prices are based on an hourly marginal band price and a penalty/bonus regime is operated relating to real time service fulfilment outturn.

Tertiary regulation is a complementary optional service but with a mandatory bid process, managed and remunerated by installed market mechanisms and the remuneration price is made up of a marginal price structure derived from the collation of allocated bids in each hour. Non-compliance with this service will result in a consequent loss of revenue.

Voltage control is partly mandatory and partly dependant on performance based contracts. The exact requirement and consequences for non compliance with the predefined contractual requirement is specified in individual participant specific contracts. No publicly available information to show how mandatory performance is monitored was available at the time of this review.

7.2.4 Evolution of Services

System Service provision in Spain significantly altered with the introduction of the liberalised electricity market in 1997. This brought some necessary changes in market operation and the provision of related system services; however, at this time only secondary and tertiary response services are sourced from the competitive market. It is expected that increased interconnection with France will impact the provision of services to the extent that more options may be available to the Spanish SO.

7.2.5 Future Developments

The projected significant increase in renewable generation in Spain could potentially influence the future development of ancillary service provision. Mention has been made of the issues facing the SO, such as the increase in demand, new interconnection and the development of new renewable generation projects.

In order to safely integrate up to 40GW wind generation it will be necessary to either impose new requirements on wind generators and/or increase the capacity of available system services. Potential solutions could be:

> To increase of storage capacity (more pump storage installations);

> Introduce more flexible thermal plants (open cycle gas turbine);

> Improve wind forecasting tools and methodologies; and

> Provide more flexible market mechanisms and regulatory measures

Looking to the future likely requirement, there is no single solution; however it would seem sensible to start to develop greater flexibility in the system, alongside certain regulatory reforms and supporting management tools. Some of the following actions may be appropriate:

> Encourage flexible and fast conventional generation with targeted economic signals.

> Introduction of negative pricing via balancing and/or energy markets.

> More SO-SO interconnections.

Integration between Spain and the rest of the Europe is still limited. The main interconnection is with France with 1400MW capacity (3% of peak demand). A new line through the eastern Pyrenees is expected to be commissioned in 2014. This project will double the size of the interconnection between two countries and new interconnector capacity will be most likely used to provide system services on a commercial basis which would have a major impact on system services in Spain. With the high variable generation penetration in many markets, system inertia is recognised as a significant issue. This is not currently a problem for the Spanish SO but with change of the kind expected in the generation mix this may well become an issue in Spain in the future. This foregoing is a condensed KEMA view as to date there is no current indication from the Spanish government or the electricity regulator as to how and when new system services will be developed.

7.3 Summary and Implications

The Spanish power network is a peninsular system with weak interconnections with France and Morocco. Spanish generation is not dominated by any single source although nuclear, gas and hydro still hold the significant share in the overall generation mix. Due to market restructuring and the attractive government feed-in tariff schemes and subsidies, renewable sources, which include solar and wind plants, are among the largest in Europe.

The existing service arrangements effectively came in force in 1998 and have not changed significantly since market introduction, although there has been significant increase in variable generation. This increase in wind and solar has a significant influence on tertiary regulation, which consists primarily of the running reserve of connected flexible plant (thermal and hydro).

Primary and secondary regulations are provided automatically and tertiary and deviation services are provided following manual instruction. The only service that is provided competitively on the competitive capacity market is secondary and tertiary control.

Integration between Spain and the rest of the Europe is still limited. Main interconnection is with France with 1400MW capacity (3% of peak demand) although a new line through the eastern Pyrenees is expected to be commissioned in 2014. This project will double the size of the interconnection between the two countries and with mainland Europe. This will provide Spain with access to the European ancillary market and will most likely have a significant impact on system services in Spain. Spain is unique amongst the markets studied in that it is peninsula and not an island and it already has interconnection with mainland Europe. This may somewhat limit its applicability to the SEM (e.g. primary reserve is less of an issue).

The annual cost of system services in 2010 was €593.8M. This represents 10.8% of total revenues in the electricity market in the Spain. EirGrid can possible take learnings from the Spanish market due to the similarities with limited interconnection and high penetration of variable generation. Any review of potential lessons from Iberia in general for the application of Ancillary Services in the SEM should carefully consider the difference in the size of the market and the generation mix, particularly the high legacy hydro capacity.

8. Ireland and Northern Ireland

8.1 Introduction and market overview

Since 1st November 2007 the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), together referred to as the Regulatory Authorities or RAs, have jointly regulated the All-Island wholesale electricity market known as the Single Electricity Market (SEM) covering both Northern Ireland and the Republic of Ireland.

The SEM includes a centralised gross pool (or spot) market – illustrated in Figure 49 below - which, given its mandatory nature for generators and suppliers, is fully liquid. In this pool, electricity is bought and sold through a market clearing mechanism, whereby generators bid in their Short Run Marginal Cost (SRMC) and receive the System Marginal Price (SMP) for each trading period for their scheduled dispatch quantities. Generators also receive separate payments for the provision of available generation capacity through a capacity payment mechanism, and constraint payments for differences between the market schedule and the system dispatch. Suppliers purchasing energy from the pool pay the SMP for each trading period along with capacity costs and system charges. The SEM rules are set out in detail in the Trading and Settlement Code (the TSC)[19].

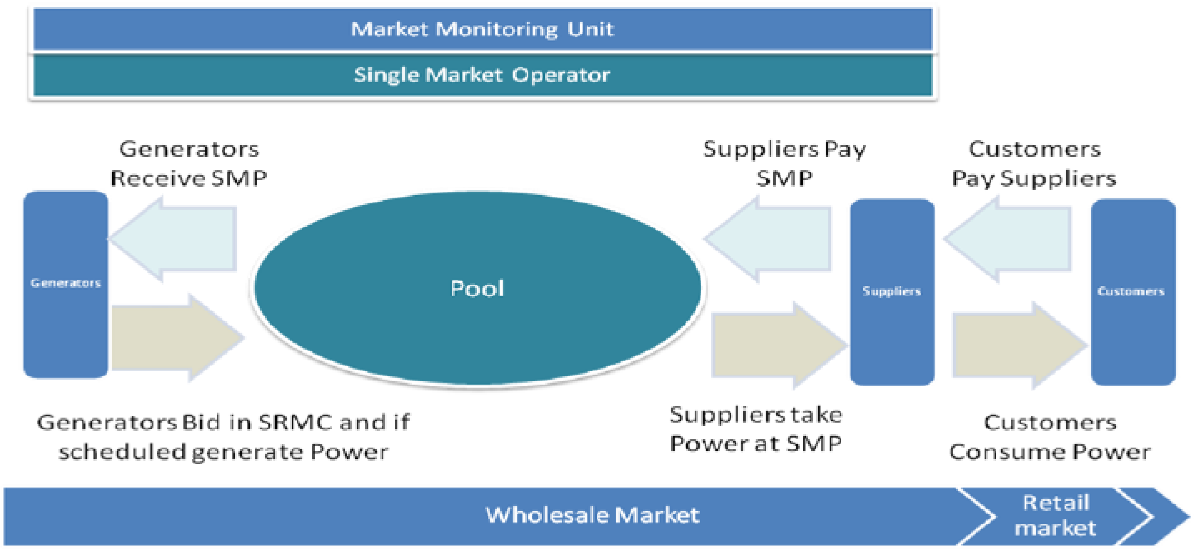

Figure 49: All-Island Single Electricity Market (Source: CER Regulator's Annual Report to the European Commission)

[19] www.allislandproject.org

8.1.1 Generation

A number of new conventional thermal generation units have connected to the system in the last twelve months, including two new Combined Cycle Gas Turbine (CCGT) Generators in the Cork area, with the maximum size of a single generator increasing to 445 MW. The total installed capacity of fully-dispatchable generation stands at 6,829 MW in Ireland and 2,328 MW in Northern Ireland at the end of December 2011.

Figure 50 below shows the approximate installed generation capacity by fuel type in Ireland at the end of 2010. Historically, coal was the most important fuel for electricity in Ireland until 1999, but it was gradually replaced by natural gas, while renewable generation capacity has been increasing rapidly in the recent years.

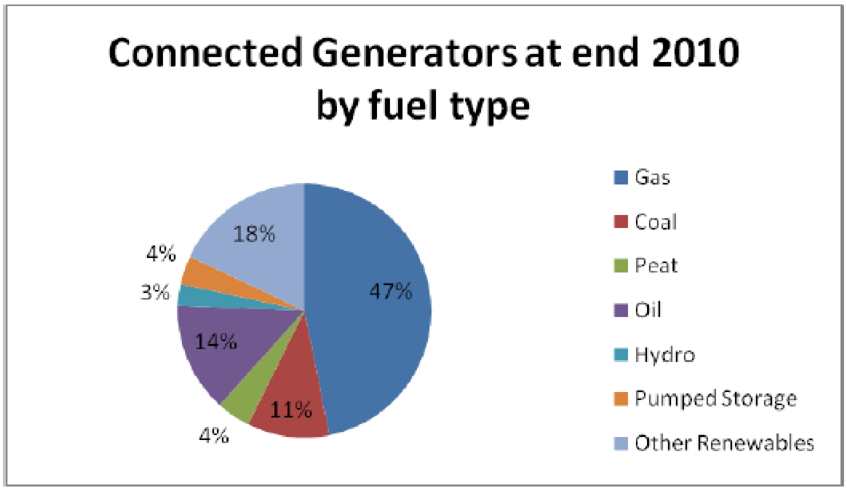

Figure 50: Installed capacity in Ireland per technology type (Source: CER Regulator's Annual Report to the European Commission)

The fuel mix for the SEM (Ireland and Northern Ireland) is set out below. This shows that gas is by far the most predominant fuel in electricity generation, followed by coal, with renewables also playing an important role.

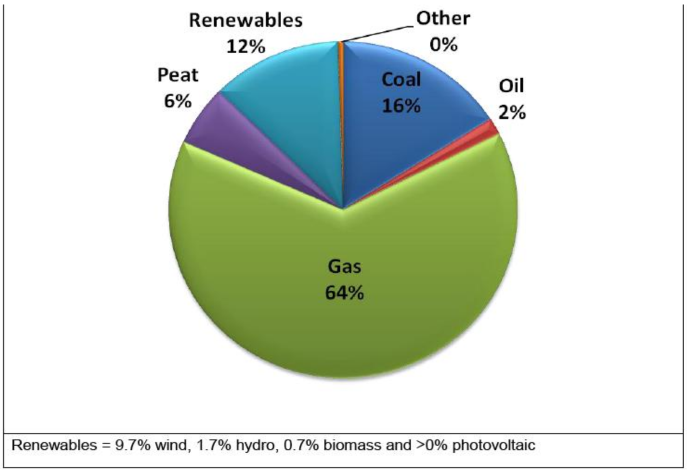

Figure 51: All-Island Fuel mix 2010 (Source: EirGrid)

8.1.2 Demand

During the period from January 2011 to December 2011, system demand in Ireland decreased. Energy consumption for the period totalled approximately 26 TWh (terawatt hours) representing a 3% increase on the 12-month period from January 2010 to December 2010. In Northern Ireland, demand levels in 2011 reached ~9 TWh.

Electricity demand in Ireland typically peaks in winter. The average demand pattern over the course of the day is quite variable, with demand typically peaking at 7:00pm. A new all-time maximum system demand of 5,090 MW occurred in December 2010. The system records for 2010 are shown in the table below:

Table 10: System Records

	EirGrid		SONI	
Record	Date	Exported (MW)	Date	Exported (MW)
Winter Night Valley	22nd Dec 2010	2,754	1st Nov 2009	605
Summer Night Valley	11th Jul 2010	1,582	12th Jul 2009	406
Mid-Day Peak	21st Dec 2010	4,410	21st Dec 2010	1,602
Evening Peak	21st Dec 2010	5,090	22nd Dec 2010	1,777
Maximum Wind	26th Dec 2010	1,228	7th Nov 2010	313
Total Exported Energy	2008	28,341 GWh	2008	9,257 GWh

8.1.3 Network

The Transmission System in Ireland is a meshed network of approximately 6,500km of high voltage, 110,000 volts (110kV), 220,000 volts (220kV) and 400,000 volts (400kV), overhead lines and underground cables and over 100 transmission stations.

Table 11: Transmission System Infrastructure 2009 & 2010 (Source: EirGrid – Transmission System Performance Report 2010)

Plant Type	2009		2010	
	No. of Items	Circuit Length (km)	No. of Items	Circuit Length (km)
110 kV Circuits	183	4,087	187	4,115
220 kV Circuits	53	1,835	55	1,850
275 kV Tie-lines	2	97	2	97
400 kV Circuits	3	439	3	439
Circuit Total	**241**	**6,458**	**247**	**6,501**
Plant Type	**No. of Items**	**Transformer Capacity (MVA)**	**No. of Items**	**Transformer Capacity (MVA)**
220/110 kV Transformers	39	7,064	39	7,064
220/110 kV Transformers	3	1,200	3	1,200
220/110 kV Transformers	5	2,500	5	2,500
Transformer Total	**47**	**10,764**	**47**	**10,764**
Total No. of sub-stations	**152**		**156**	

The Northern Ireland transmission network is owned by NIE and operated by SONI and comprises approximately 2,100 km of circuits, including 400 km of 275kV double circuit lines and 1,700 km of 110kV double and single circuit lines, which link Northern Ireland's three principal power stations and external connectors to 30 main sub-stations across Northern Ireland.

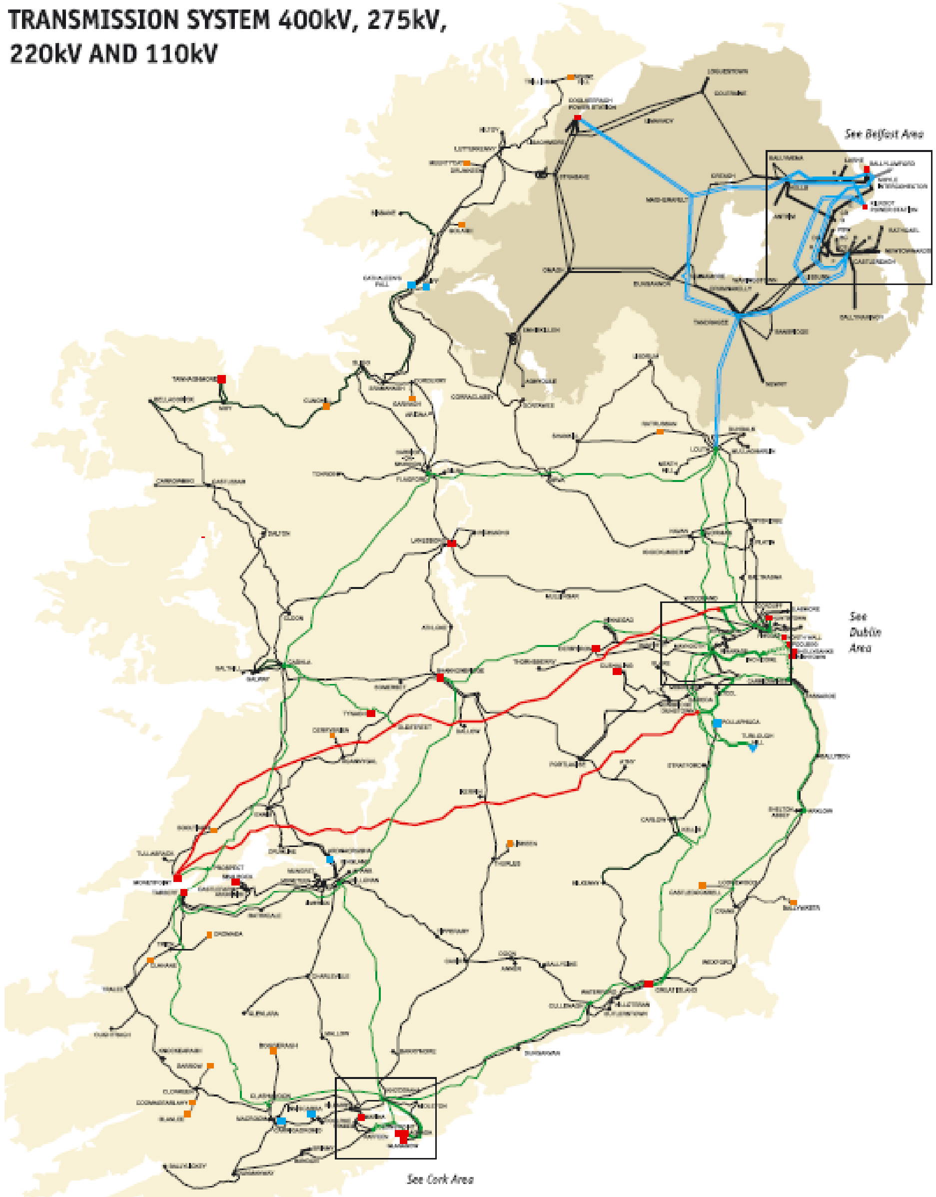

Figure 52: Ireland's and Northern Ireland's Transmission System

8.2 Services used by the TSOs

In its capacity as TSO, EirGrid has developed a set of definitions for Ancillary Services in Ireland, as well as a set of payment arrangements for each Ancillary Service in harmonisation with Northern Ireland.

The contracted Ancillary Services in Ireland are:

> Reserve: In the event of a loss of output from a generation unit or an unexpected change in system demand, it is essential to be in a position to make up the shortfall, either from generation units or other sources. Arranging for demand customers to

reduce their electricity requirements can also provide reserve. To cater for different situations that may arise on the transmission system, reserve is contracted over a variety of time scales.

> Reactive Power: This is required to maintain voltage balance on the transmission system on a regional basis. Both static and dynamic provision of reactive power is required.

> Black Start: This is the ability of a generating set to start up and provide electricity to the transmission system without an external power supply. Service providers are contracted to provide black start services through the AS agreements in Ireland and Connection Agreements in Northern Ireland. Depending on the station they are paid an hourly availability rate to recover costs associated with capital, maintenance, TSO-initiated testing and usage costs for the provision of this service. In the event that a station fails a TSO-initiated black start test, then the service provider will receive a charge.

Similarly for reactive power, the TSOs must maintain a voltage balance across the transmission systems in order to maintain a secure and stable power system and to avoid damage to connected equipment. To maintain the balance, the appropriate level of reactive power (leading and lagging) is required at appropriate locations in the transmission system. The required level of reactive power varies in the operational timeframe. Reactive power is mainly provided by generator units and transmission assets. Generally, reactive power must be provided close to the location where it is needed. Overall, therefore, the requirement is for the flexible provision of reactive power at appropriate points across the transmission systems. Service providers are contracted to provide reactive power through the AS Agreement and are paid for leading and lagging reactive power based on their declared reactive power availability when they are synchronised to the transmission system.

A schematic diagram of the Ancillary Services that are contracted in the SEM market is presented in Figure 53 below:

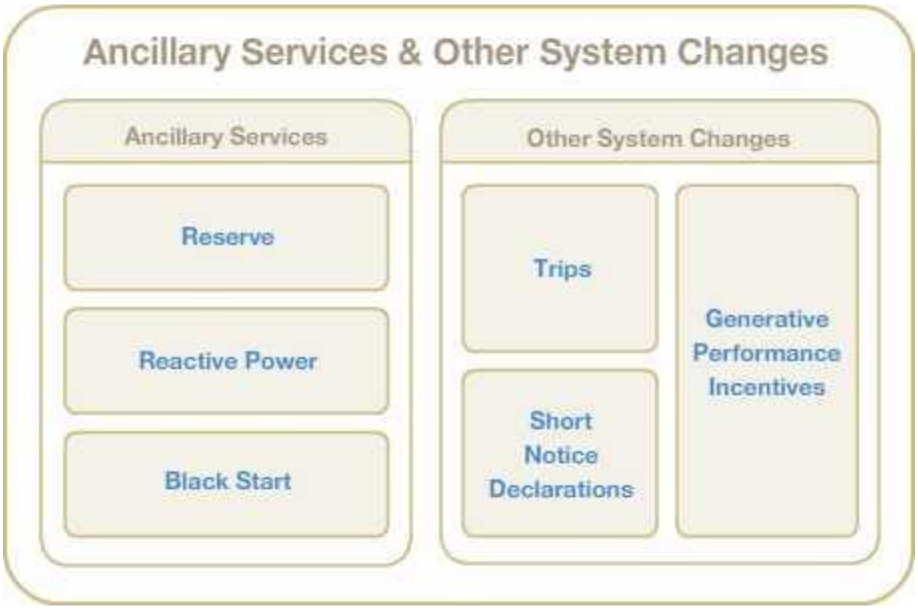

Figure 53: Ancillary Services contracted in SEM

The Operating Reserve definitions operated in Ireland are as follows:

(a) **Primary Operating Reserve (POR):** The additional MW output (or reduction in demand) at the frequency nadir compared to the pre-Incident output (or demand), where the nadir occurs between 5 and 15 seconds after the event. If the actual frequency, nadir is before 5 seconds or after 15 seconds after the event, then for the purposes of POR monitoring the nadir is deemed to be the lowest frequency which did occur between 5 and 15 seconds after the event.

(b) **Secondary Operating Reserve (SOR):** The additional MW output (or reduction in demand) compared to the pre-incident output (or demand), which is fully available and sustainable over the period 15 to 90 seconds following the event.

(c) **Tertiary Operating Reserve 1 (TOR1):** The additional MW output (or reduction in demand) compared to the pre-incident output (or demand), which is fully available and sustainable over the period 90 to 300 seconds following the event.

(d) **Tertiary Operating Reserve 2 (TOR2):** The additional MW output (or reduction in demand) compared to the pre-incident output (or demand), which is fully available and sustainable over the period 300 to 1200 seconds following the event.

(e) **Replacement Reserve:** The additional MW output (and/or reduction in demand) required compared to the pre-incident output (or demand) which is fully available and sustainable over the period from 20 minutes to 4 hours following an event. The purpose of this category of reserve is to restore primary reserve within 20 minutes including restoring any interruptible load shed.

Table 12: Operating Reserve Requirements (Source: EirGrid)

Category	All Island Requirement % Largest In_Feed	EirGrid Minimum (MW)	SONI Minimum (MW)
POR	75%	120 / 75	50
SOR	75%	120 / 75	50
TOR 1	100%	120 / 75	50
TOR 2	100%	120 / 75	50

Table 13: Sources of Reserve (Source: EirGrid)

	EirGrid	SONI
Dynamic Reserve	Synchronised Generating Units	
Static Reserve	Turlough Hill Units (Pump storage) when in pumping mode Interruptible Load (30 MW 07:00 – 00:00)	Moyle Interconnector (75 MW)

8.2.1 Procurement of Services

On the 1st February 2010, harmonised All-island arrangements were brought into operation for both Ancillary Services and Other System Charges.

The prudent level of operating margin required for the island is set jointly by the TSOs. Critical factors which input into setting that prudent level include the largest in-feed on the island, variability in load and generation in the operational timeframe, generation reliability and the reliability of provision by service providers of reserve. Service providers are contracted to provide reserve through the AS agreements and are paid for the different categories of reserve (Primary Operating Reserve, Secondary Operating Reserve, Tertiary Operating Reserve 1, Tertiary Operating Reserve 2, Synchronised Replacement Reserve and De-synchronised Replacement Reserve) based on their declared availability. If during a frequency event the service provider does not provide the expected level of reserve then the TSOs levy a charge on the service provider for the first three categories of reserve.

Under Harmonised Ancillary Services, service providers are paid for the provision of six categories of reserve and are exposed to charges for the first three categories of reserve –

Primary, Secondary and Tertiary 1 operating reserves. These charges are calculated based on the level of under provision and the hourly payment rate.

The payment for the provision of reactive power is set out in the harmonised all-island Ancillary Services agreement. Payment is calculated based on the service provider's capability to provide reactive power at the lower voltage side of grid connected transformer and is made on a half hour trading period basis. The average MW output metered reading comes from the HV side of the grid connected transformer.

8.2.1.1 Reactive Power arrangements for Wind Farms

While historically wind farms have not provided AS, the introduction of new Wind Grid Code provisions now requires wind farms to have a degree of voltage control capability.

For wind farms, the capability to provide reactive power is determined from the generator-specific Reactive Power Characteristic Curve which is derived from the Grid Code and the average MW output for each trading period. The Reactive Power Characteristic Curve is agreed as part of a schedule to the AS agreement. The Reactive Power Characteristic Curve reflects the generator characteristics, connection characteristics, testing, reliability and usefulness of the service to transmission system operation.

All Grid Code compliant wind farms are paid for Reactive Power utilisation (i.e. production and consumption of Reactive Power) but only WFs with a Reactive Power capability that is not dependant on energy production are paid for Reactive Power capability. Both utilisation and capability payment rates for wind farms are the same as for thermal and hydro generators.

Due to the nature of the reactive power payments to wind farms (included under the reference of „non-Centrally Despatched Generator Units in the AS agreement), the onus is on the service provider to ensure and to prove their ongoing reactive power capability. The service provider should inform the TSO of any reductions in reactive power capability. The TSO regularly tests for the provision of the service. Should an issue arise with respect to the provision of the service, the TSO reserves the right to pause AS payments and notifies the service provider of the pause in payments.

Provision for Reactive Power payments to wind farms was specifically allowed in the 2006-2010 Revenue Determination. Table 14 below presents the total Reactive Power payment allowance made in the Determination and the proportion of this allowance that was estimated for payment to WFs (the remainder being the estimated payment to thermal and hydro generation).

Table 14: Reactive Power Expenditure Allowance 2006-2010 (in 2004 money)

	2006	2007	2008	2009	2010
Total Reactive Power Allowance (€m)	10.87	11.66	11.78	12.05	11.82
Wind Farm Allowance included in the above figure (€m)	0.45	0.79	1.15	1.39	1.65

8.2.2 Cost Recovery

In relation to AS payments are made outside of the Single Electricity Market (SEM) by the TSOs. These payments have been harmonised between Ireland and Northern Ireland since Ancillary Service Harmonisation "Go-live" on the 1st February 2010. These payments & charges are specified annually in the Statement of Payments and Charges. The Ireland AS allowance covers reserve, reactive power, black start and synchronous compensation, while the Northern Ireland AS allowance includes reserve and reactive power (including the reactive part of synchronous compensation payments).

The table below sets out the payment rates applicable (from 1st October 2011) to the calculation of payments and the charge rates/parameters applicable to the calculation of charges for Primary Operating Reserve, Secondary Operating Reserve, Tertiary Operating Reserve 1, Tertiary Operating Reserve 2 and Replacement Reserve under Schedule 2 of the Ancillary Services Contract.

Table 15: Ancillary Services Payment Rates

Ancillary Services Payment Rates		
Payment Parameters and Rates	**EirGrid**	**SONI**
Primary Operating Reserve	€2.22 / MWh	£1.95/ MWh
Secondary Operating Reserve	€2.13 / MWh	£1.87/ MWh
Tertiary Operating Reserve 1	€1.76 / MWh	£1.55/ MWh
Tertiary Operating Reserve 2	€0.88 / MWh	£0.77/ MWh
Replacement Reserved (Synchronised)	€0.20 / MWh	£0.18/ MWh
Replacement Reserve (De-Synchronised)	€0.51 / MWh	£0.45/ MWh

Charge Rates/Parameters for Under provision	EirGrid	SONI
POR Charge Period	30 days	30 days
SOR Charge period	30 days	30 days
TOR1 Charge Period	30 days	30 days
Event Frequency Threshold	49.5 Hz	49.5 Hz
Reserve MW Tolerance	1 MW	1 MW
Reserve Percentage Tolerance	10%	10%

Table 16 below sets out the payment rates applicable (from 1st October 2011) to the calculation of Reactive Power Capability Payments (Leading) and Reactive Power Capability Payments (Lagging) under Schedule 3 of the Ancillary Services Contract, whereas Table 17 presents the Black Start Service Rates set by EirGrid.

Table 16: Reactive Power Capability Payments

	EirGrid	SONI
Reactive Power Capability (Lagging)	€0.13 / MVArh	£0.11/ Mvarh
Reactive Power Capability (Leading)	€0.13 / MVArh	£0.11/ Mvarh
Automatic Voltage Regulator ON Factor	2	

Table 17: Black Start Rates

Black Start Parameter	Rate
Black Start Charge Period (Partial Fail)	30 days
Black Start Charge Period (Total Fail)	90 days

Table 18 below details the approved revenue for Ancillary Services for the tariff year 2011-2012 as submitted to the RAs by the System Operators, as follows:

> By SONI, in its capacity as licensed transmission system operator in Northern Ireland;

> By EirGrid, in its capacity as licensed transmission system operator in Ireland.

This is in accordance with the separate licensing and regulatory arrangements as apply in Northern Ireland and Ireland. The table is an estimate of the ex ante provision for Ancillary Services and is premised upon a number of assumptions; for example in the Ireland case, there is no specific revenue allowance or provision for the tariff year 2011/12 as the Ireland revenues are arranged on a calendar year basis. The distinct licensing and legislative frameworks in Northern Ireland and Ireland currently do not provide for the determination of a single Ancillary Services pot across the island.

Table 18: AS Allowance for 2011-2012

	NI (£m)	ROI (€m)	Total (€m)
Reserve	£7,28	€24,20	€32,47
Reactive Power	£3,12	€11,10	€14,61
Black Start	n/a	€1,8	€1,8
Other	£0,64	€0,60	€1,32
TOTAL	£11,04	€37,67	€50,20

8.2.3 Compliance and Performance Monitoring

There are a number of system services charges levied on producers, which intend to incentivise behaviour that enhances system security and reduces operating costs. These charges, which were also harmonised in February 2010, are divided into the following:

> Trip Charge

> Short notice Declaration Charge

> Generator Performance Incentive Charge

In the event of a generator unit tripping a Trip Charge is levied on the service provider depending on how the unit tripped (i.e. slow wind down, fast wind down, direct trip). The purpose of the trip charge is to minimise the number of trips and, when a trip is unavoidable, to incentivise a generator to wind down a unit as slowly as possible.

In the event of a generator unit making a downward declaration of their availability at short notice a Short Notice Declaration (SND) Charge is levied on the service provider depending on the amount of notice given.

The harmonised arrangements establish Generator Performance Incentive (GPI) Charges monitoring and performance incentives on an all Island basis. The arrangements are intended to quantify and track generator performance, identify non-compliance with standards and help evaluate the performance gap between what is needed and what is being provided by services providers as the power system develops.

Table 19 below presents the regulatory-approved rates applied for the Generator Performance Incentive charges from October 2011.

Table 19: Generator Performance Incentive Charge Parameters & Rates

Half Hour Trading Period Charges	
Minimum Generation	€1.18 / MWh
Max Starts in 24 hour period	€1.00 / MWh
Minimum On Time	€1.00 / MWh
Reactive Power Leading	€0.29 / MWh
Reactive Power Lagging	€0.29 / MWh
Governor Droop	€0.29 / MWh
Primary Operating Reserve	€0.12 / MWh
Secondary Operating Reserve	€0.12 / MWh
Tertiary Operating Reserve 1	€0.12 / MWh
Tertiary Operating Reserve 2	€0.12 / MWh
Late Declaration notice Time	480 min
Event Based Charges	
Loading Rate	€0.59 / MWh
Loading rate Factor 1	60 min
Loading Rate Factor 2	24
Loading Rate Tolerance	110%
De-Loading Rate	€0.59 / MWh

De-Loading Rate Factor 1	60 min
De-Loading Rate Factor 2	24
De-Loading Rate Tolerance	110%
Early Synchronisation	€2.65 / MWh
Early Synchronous Tolerance	15 min
Early Synchronous Factor	60 min
Late Synchronisation	€26.47/ MWh
Late Synchronous Tolerance	5 min
Late Synchronous Factor	55 min

8.2.3.1 Participant compliance and performance monitoring

Performance parameters

Performance parameters that the TSO monitor include the following:

> compliance with Dispatch Instructions;

> compliance with Declarations including, without limitation, in respect of:

- Primary, Secondary and Tertiary Operating Reserve provided by each of a Generator's Generation Units, following a low Frequency Event on the Transmission System;
- Frequency Regulation provided by each Generation Unit (to confirm that it is consistent with the Declared Governor Droop); and
- Tertiary Operating Reserve 2 and Replacement Reserve provided by each of a Generator's Generation Units.

8.2.4 Evolution of Services

A joint Regulatory Authority/TSO project was carried out throughout 2008 and 2009 with a view to harmonising the jurisdictional arrangements for the procurement of these services across the island. The review also included introducing charges to generators for non-compliance with key Grid Code areas, i.e. Grid Code Performance Incentives, as well as harmonising arrangements relating to generator trips and short-notice declarations.

Following a decision by the SEM Committee in January 2009 on the all-island policy for these Ancillary Service-related areas, a consultation paper on the proposed rates and charges to apply was published in June 2009. A final decision on these all-island payments and Reactive Power charging arrangements for the period from 1st February to 30th September 2010 was then published by the Regulatory Authorities in January 2010 covering:

> Ancillary Services - Reserve, Reactive Power and Black Start;

> Generator Trip and Short Notice Declaration Charges; and,

> Generator Performance Incentives.

Accordingly the new harmonised all-island Ancillary Service-related arrangements went live on 1st February 2010. The rates for the services are reviewed annually following public consultation. This also allows for refinement of the existing design of the services.

8.2.5 Future Developments

On 18th April 2011, the Transmission System Operators, EirGrid and SONI, published a consultation on revised Ancillary Services rates and Other System Charges. In accordance with the SEM Committee's decision papers on Harmonised Ancillary Services and Other System Charges the TSOs have now concluded the consultation phase and have recommended new services to the RAs and the SEM Committee for the forthcoming 2011-12 tariff period.

The new services proposed by the TSOs are:

> Reduced Time to Synchronise (new short term service)

> Flexible Multimode Operation (new short term service)

> Lower Minimum Generation (new short term service)

> Synchronous Compensation (new service)

9. Comparison of International Markets Studied

This concluding section provides a comparison of the different international markets studied. The assessment is broken down into two sub-sections and provides tables with indicative figures to highlight:

- The comparison of key features of each national market; and
- The Comparison of approaches to system services in general.

9.1 Comparison of Key Features

In comparing the various approaches adopted for the provision of system services in each of the markets studied, it is useful to compare some of the key general facts and figures relating to the overall wholesale markets. Thus the table below provides a comparison of key features and statistics relating to the overall market for Great Britain, New Zealand, Tasmania, Singapore, Cyprus and Spain alongside the equivalent details for Ireland:

Table 20: General overview of the studied (island) markets

	SEM	GB	New Zealand	Tasmania	Singapore	Cyprus	Spain
Total Annual Energy Demand	35TWh	380TWh	39.038TWh	10.80TWh	40TWh	4.7TWh	275.7TWh
Peak Demand	6,410 MW	59,100MW	6,600MW	2,111MW	6 494MW	1103MW	44,122MW
Installed Gen Capacity	911.4 GW	81.3GW	9.1GW	2.798GW	9.9GW	1.438MW	97.447GW
Types of generation	7.4% coal 45.5% gas 2.1% hydro 12.22% oil 20% wind 6.3% distillate 2% peat 2.5% pumped storage 1.98% other	39% conventional 37.8% gas CCGT 12% nuclear 4.7% hydro 2.5% wind 4% other	56.4% hydro, 21.2% gas 12.8% Geothermal 4.5% Coal 3.7% Wind 2.3% Other	69% hydro, 12% thermal 4% Wind 15% Basslink	c.62% gas CCGT c. 32% steam plant <3% gas OCGT 3% other	83% HFO 17% OCGT	11% coal 29% gas CCGT 8% nuclear 20% hydro 20% wind 4% solar 8% other
Inter-connectivity	500 MW with Scotland	2GW with France; 400MW with Island of Ireland, 1000 MW with the Netherlands	None (but 1050 MW HVDC link between the North and South Island)	600MW HVDC Basslink to Victoria	None	None	1.3GW with France (AC), 2.4GW with Portugal and 900MW with Morocco (*source: REE*)
Number of Participants	1 large generator, 8 with market share < 12% 2 TSOs (EirGRId and SONI) 2 DNOs (ESB and NIE) 5 main suppliers	6 large vertically integrated participants,11 other generators with >500 MW, 1 additional business only suppliers, Some small suppliers	5 generators, 1 transmission, 28 distribution, 17 retailers (7 dormant)	1 generator, 1 transmission, 1 distribution/ franchise supply, 5 Tasmanian participants in NEMMCO	6 generators, 6 suppliers	1 generator, 1 supplier	4 large vertically integrated companies, 1 Transmission

Privatisation / liberalisation (date)	NI Privatised 1992, RoI market in place since 2000.	1989	Market opening Oct 1996	Dis-aggregation July 1998 Limited market opening July 2006	1995 – Pool 2003 - NEM	T&D rules – 2005 Trading rules – 2007	1998-Spanish electricity pool 2006-Iberian Electricity Market

Key points arising from this are:

- GB represents a large market relative to the other island markets investigated. This scale means that there is more incentive to put in place complex market arrangements as the potential savings are more significant;

- The mix of generation varies significantly across markets and this has implications for the level of system services required. GB has the most similar mix with Singapore also having a high level of CCGTs. Spain, New Zealand and particularly Tasmania have large amounts of hydro plant, which has implications for the generation margin required, and the levels of reserve they need to hold. Spain like Ireland has high level of wind generation penetration but significant number of flexible generation;

- The levels of interconnection vary. Cyprus and Singapore have no interconnection and New Zealand has no interconnection to Australia, but basically consists of two individual Islands that are highly interconnected. GB and Spain have interconnection, but it is a relatively small proportion (4% and 3% respectively) of peak demand. Tasmania has interconnection that is equivalent to around 25% of internal demand;

- Tasmania and Cyprus both only have one supplier and generator which reduces competitive pressure. However, with the introduction of the Basslink interconnector Tasmania has become part of the wider Australian System which re-introduces commercial pressures. Cyprus is not a fully competitive market due to the relatively recent nature of liberalisation and current monopoly suppliers.

9.2 Comparison of Approaches to Service Provision

This section provides a thorough comparison of all aspects of the services adopted in each of the markets reviewed, covering technical aspects, commercial/regulatory provision and supporting financial arrangements.

9.2.1 Comparison of Services Provided

In the first instance it is important to clearly understand the different technical services (and their definitions) as utilised by each market and categorised under the 'umbrella' of system services. A summary comparison of the markets studied in this report is provided in the table below alongside the equivalent details for Ireland and Northern Ireland:

Table 21: Technical overview of system services in the studied markets

	SEM	GB	New Zealand	Tasmania	Singapore	Cyprus	Spain
Dynamic Frequency Response	Continuous	Continuous	Continuous - Frequency Regulating Reserve (frequency keeping)	Continuous - Regulating services and network loading control	Continuous	Continuous	Continuous
Primary Reserve	Response from 5s to 15 s	Generation: Continuous >50MW Load shared: Within 10s, at least 20s	Instantaneous Reserves Fast (6 sec);	Contingency FCAS Fast (6s) Slow (60s)	Response 1s, until SR comes in	Response form 5s to 15 s	Primary Regulation (<15s to 15 min)
Secondary Reserve	Response from 90s to 5min	Response 30s, at least 30min	Sustained (60 sec)	FCAS delayed	Response 30s, until CR comes in	Response from 90s to 5min	Secondary Regulation (≤100 s to 15 min)
Tertiary Reserve (timings)	Response from 90s to 20min	not used	Not used	Short-term capacity reserve	(contingency) Response 10 min, until end	Response from 5min to 20min	Tertiary Regulation (<15 min to 2 hours)
Reactive Power	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional	>30MW Generation mandatory ±MVAr (Rules requirement) Commercial additional	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional	Generation mandatory ±MVAr (Rules requirement) Steady State Commercial additional
Black Start	Independent grid re-start using diesel(s)	Independent grid re-start using diesel(s)	Independent grid re-start using diesel(s)	Independent grid re-start using diesel(s)	Independent grid re-start using diesel(s)	Independent grid re-start using diesel(s)	Does not exist
Other	Replacement Reserve from 20min to 4hrs Min load capabilities Min on time & min off time Governor droop capability	FR: Response 2 min, 25MW/min, at least 15min SR: Response 20min, min 3MW, at least 2 hrs (high freq) within 10s STOR: Response 240 min, min 3MW, at least 2	Over-frequency reserve	Network control (to manage interconnectors)	Fast Start (from OCGTs as in GB)	Replacement Reserve from 20min to 4hrs	Slow reserve- Running reserves of connected thermal units (30 min. to 4-5 hours)

		hrs						
	Load/deloading rates							

Key points arising from this exercise are:

- A similar technical mix of services is applied across all countries;
- Reactive power is a mandatory requirement for all generators above a de-minimus limit. Where additional reactive power is required there are commercial arrangements in place to procure it;
- Dynamic Frequency Response is instantaneous for all countries examined. Different definitions exist for primary, secondary and tertiary reserve reflecting time to respond and length of time for provision of the reserve – this in turn reflects the "sensitivity" of system frequency to system events, reflecting system size (in demand terms) and unit size of generators (as a proportion of demand);
- The primary focus on frequency control as an important system services reflects the island nature of all countries examined;
- As the largest market with a low plant margin and widest constituency of potential service providers, GB has the most provision and the widest array of commercially procured services for frequency control and reserve.

9.2.2 Comparison of the Commercial/Regulatory Treatment of System Service Provision

The second aspect of system services as utilised in each market is to understand the similarities and/or differences in the country specific commercial arrangements for the system services they deploy. A summary comparison is provided in the table below:

Table 22: Commercial/regulatory overview of system services in the studied markets

	Ireland (RoI&NI)	GB	New Zealand	Tasmania	Singapore	Cyprus	Spain
Mandatory* AS	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision	Rules obligations, frequency capability and minimum voltage provision
Commercial AS	Primary, Secondary, Tertiary Operating Reserve, Synchronised Replacement Reserve and De-synchronised Replacement Reserve	Black Start; Fast Start; Frequency Response; Enhanced Reactive Service; Fast Reserve; Short Term Operating Reserve; Intertrip; Emergency Assistance; Maximum Generation Service	Reserve markets Contracts for Reactive Power and Black Start	Reserve markets Contracts for Reactive Power and Black Start	Regulation and Reserve markets Contracts for Reactive Power and Black Start	All System Services	Secondary, tertiary regulation, Deviation management Contracts for Reactive Power
Method of Procurement	Market arrangements and Bilateral Contracts	Market arrangements and Non-Tendered Bilateral Contracts	Reserves market Tender for other	Reserves market Tender for other	Regulation and Reserves – market Tender for other	Bilateral negotiation with monopoly generator	Market arrangements and Bilateral Contracts
Payment for AS	Cost are socialised amongst consumers	Uplift in transmission charges	Reserve SMP Tenders (pays as bid) for other	Reserve SMP Tenders (pays as bid) for other	Regulation and Reserve SMP Tenders (pays as bid) for other	Agreed contract tariff (pay as bid)	Secondary & Tertiary reg: paid by generation and demand units which deviate from program Tenders (pays as bid) for other
Degree of Transparency	Market Reports and data on requirements and costs for all System Services	Market Reports and data on requirements and costs for all System Services – some variation in transparency	Reserve – market SMP Open tender	Reserve – market SMP Open tender	Reserve – market SMP Open tender	None	None

Relationship to Energy Market	Regulation and Reserve via co-optimised despatch	Utilisation of some System Services interact with operation of BM (GBSO can forward trade for balancing)	Reserve via co-optimised despatch	Reserve via co-optimised despatch	Regulation and Reserve via co-optimised despatch	Separate	Regulation and Reserve via co-optimised despatch
Role of the Regulator	Sets governance framework; sets overall cost incentive; rules on proposed AS changes, seeks to promote more use of market mechanisms and greater info transparency	Sets governance framework; sets overall cost incentive; rules on proposed AS changes, seeks to promote more use of market mechanisms and greater info transparency	Sets governance framework; oversees costs; rules on proposed new AS related assets	Limited role; market rules of NEMCO largely set AS framework	Sets governance framework; investigates high AS costs and/or inappropriate AS market behaviour	Highly interventionist; plays active role in AS negotiations and contract determination	Limited role
Evolution Process	Commercial AS approach since	Core AS in place since 1960's; some market in 1990s; new AS and markets since NETA; ongoing evolution as wider market evolves	Reserve market since 1996	Reserve market since 2005	AS markets introduced in 2003	Commercial AS approach introduced in 2005	Commercial AS approach in place since 1998
Future Development	The new services proposed by the TSOs are: Reduced Time to Synchronise) >Flexible Multimode Operation >Lower Minimum Generation >Synchronous Compensation	Potential revision of FR and RP arrangements to combat high costs and encourage competition Introduction of formal SO-SO AS arrangements (with potential future cross border AS provision) Forthcoming global review of SO role inc. all aspects of AS	Increasing genset size, and variable nature of some generation could require changes.	Potential changes to the way the Basslink interconnector operates to improve the level of frequency deviations in Tasmania	Potential review of regulation in light of high current costs	Further development if and when new generation entrants site in Cyprus	>Encourage flexible and fast conventional generation with targeted economic signals. >Introduction of negative pricing via balancing and/or energy markets. More SO-SO interconnections

Key points arising from the table are:

- All countries have mandatory requirements for frequency capability and minimum voltage capability;

- All countries except for Cyprus have market arrangements for procuring (some but not all services) their system services. GB has some non-tendered bilateral contracts for certain types of service which are less competitive, and Cyprus exclusively adopts bilateral service contracts given that these are provided by the monopoly generator. The degree of intrervention by the Regulator also reflects the extent of market approaches i.e. regulatory involvement in Cyprus is (by far) most intrusive and in New Zealand and Tasmania it is the least intrusive;

- Reserve markets are common in all the well developed system services markets where New Zealand, Tasmania and Singapore have integrated their reserve requirements into the mainstream energy markets. For these countries their system services (Reserve and Energy markets) are co-optimised. For New Zealand and Tasmania this reflects the high presence of hydro and island interconnectivity – Singapore has chosen to follow this model but very high costs are being experienced as a result. The GB market also has some interaction between the system services required and the operation of the Balancing Mechanism (and thus the mainstream energy market). This is driven by overall SO cost incentives on the GBSO but incorporates the freedom to choose the most economic options (inc. forward energy trading). Cyprus, due mainly to its relatively recent deregulation, currently has completely separate markets;

- There is a general preference for market based solutions with regulators generally adopting a light touch approach, with the possible exception of Cyprus where the market has yet to fully develop;

- Most countries examined have moved straight to the final solution rather than evolving through a number of stages (Not GB – see also section 13);

- The additional GB system services observed and the complexity of the supporting arrangements could be seen as a characteristic of a less favourable generation mix and a greater need for frequency control;

  In table above: there should be a distinction made between mandatory unpaid services and mandatory services that are remunerated.

9.2.3 Comparison of System Services Costs and Cost Treatment

The third and final aspect of system services as utilised by each market studied by KEMA in this Report to consider is the costs of the system services adopted by each market and their treatment within the market. A summary comparison is provided in the table below:

Table 23: Comparison of the costs of system services in the studied markets

	SEM	GB	New Zealand	Tasmania	Singapore	Cyprus	Spain
Cost of System Services	€50.2 m	c.£546.77m in 2010/11 £1=€1.15 c.629m Euros	NZ$90.5m 1.72$NZ= €1 €50.27m	$AU12.115m 1.34$AS = €1 €9.04m.	SG$1270m 1$SG = €0.57 €723.9m	€13-30m (estimates)	€ 593.80
Cost of System Services as a fraction of the total Electricity Market	~2.5%	~1.8%	~1.5%	~1.5%		2-3%	10.80%
Cost of System Services per MWh of demand	35 TWh €1.43/MWh in 2011	XX TWh £1.44/MWh in 2010/11 c.1.656 Euro/ MWh	41.3 TWh c.1.217 Euro/ MWh	10.95TWh c.0.825 Euro/MWh	33TWh c.21.9 Euro/MWh	5.133GWh c.2.75-6.4 Euro/MWh	3.75 Euro/MWh
Cost Recovery	AS payments outside the SEM by the TSOs. Annual payment rates are set, applicable to the calculation of charges.	Via specific charge, BSUoS, levied pro rata on combined MWh of generators and suppliers	Frequency keeping – demand; Reserves, generation and SO (for HVDC); Voltage – zonal distribution	Regulating – causer pays and market customers; Contingency – market generators and customers	Reserve – generators pro rata on MWh Regulation – generators for 5MW per unit then rest on consumers Reactive Power – T connected consumers (minor cost) Black Start – consumers on MWh basis	Paid by consumers (i) Operating reserve pro rata on MWh by settlement period (ii) Rest pro rata on monthly MWh	Market participants and end customer
Cost incentivisation	Market-based costs. Pass-through	AS costs within overall Balancing costs (external and internal to GBSO) subject to overall GBSO BSIS Scheme	Market-based costs. Pass-through	Market-based costs. Pass-through	Market-based costs. Pass-through	Direct regulatory involvement in ASS contract agreement	Market based costs

Key Points to note are:

- Wide variation of costs on a per MWh basis between countries. This reflects a number of variables including:
  - Size of the market/system with significant economies of scale achievable
  - Plant mix (especially access to hydro)
  - Level of interconnection
  - Competitiveness of the procurement process
  - Network size and shape (which e.g. influences reactive power need)
- Cyprus is the only market where all charges fall on suppliers. In the other markets a mixed approach is taken with some costs facing suppliers, some generators and some both. In all three countries with a co-optimised reserve and energy market the reserve costs fall exclusively on the generators.
- GB is the only market with an explicit incentive scheme to minimise overall balancing services costs (which includes system services). New Zealand, Tasmania and Singapore all adopt market based cost systems with pass through. Cyprus is the opposite extreme with the regulators having direct involvement in the development of system services contracts.

10. Characteristics of individual markets

This section outlines some of the key features of the system services in each of the individual markets studied and highlights key points for consideration.

10.1 Great Britain

The following points have been assembled as specific learnings from the GB review.

- The GB market is large in relation to the other markets reviewed with a complex interconnected network. It is over ten times the size of the SEM and has relatively high system services revenues, in the order of £547 million. The market is supported by a mature set of commercial arrangements aimed at maximising service provision at minimum cost. Such arrangements are transferable to other markets in part or full depending on the level of maturity and interaction between competing participants. From the international review undertaken, GB is by far the most advanced electricity market (from both a wholesale and retail perspective) and could therefore serve as a suitable development platform for future service development in the SEM.

- GB has significantly less wind than Ireland and Northern Ireland, although wind generation is growing in GB and is already driving complexity in real time system operation. This calls for greater innovation in the development of system services as traditional generation is replaced by renewable alternatives with different and more dynamic technical performance characteristics.

- The GB market generally enjoys a healthy competitive mix of system service providers reflecting the availability of 17 market participants with generation assets over 500MW. However, this can mask the differing technical capability of varying generation technologies e.g. coal vs. pumped storage. For certain system services where competition is relatively low, bilateral agreements are applied either partially or for the full service requirement. As a trade off, this results in a reduction of available operating information (less transparency) to enable the GBSO to control costs. A good example of this is in the area of fast reserve where pumped storage plant owned by First Hydro dominates the market (unique technical plant capability) and National Grid has little option other than to continue to place a significant proportion of bilateral contracts with First Hydro in order to meet fast reserve needs.

- Moves to a market based solution in GB have not been particularly successful. A topical example is the frequency response market where under regulatory pressure National Grid introduced a more market based procurement solution. The impact of this was that costs doubled due to the fact that they were classified as a relatively distressed buyer (in economic terms) being served by a pseudo cartel of active providers (it is possible for someone to effectively opt out by submitting a very high price – this enables reduced operational wear and tear on equipment and associated capital and running costs). National Grid has since sought to modify the supporting market mechanisms to mitigate these higher costs with limited success and thus continue to examine a more appropriate solution.

- A further observation is that where a system service is dominated by one or a few providers and/or the costs of procuring those services are very high, the GBSO actively seeks to replicate those services in other ways to reduce their dependency in that area (e.g. layering of BM offer acceptances to create a fast dynamic increase in generation at times of fast rising demand rather than using Fast Reserve at high cost) but also actively seeks to encourage new entrant providers for the wider market e.g. demand side options.

- The system services market in GB has gradually evolved since privatisation into a substantially different set of arrangements to those that pre-ceded the liberalised arrangements. This reflects both the ongoing change witnessed in the structure and behaviour of the market which in turn has altered the needs of the SO. For example the implementation of NETA did not immediately bring about an attempt to co-implement a radical new system services regime, as the primary focus was successful implementation of the electricity wholesale market. It was also recognised that experience of market behaviour and system operation issues under the NETA was required before embarking on development of system services. As the new market for traded energy developed so too did the provision of system services, driven largely by the objective to reduce costs under the overarching GBSO incentive scheme. This process is still evolving to the extent that one of the latest initiatives aims to make more extensive use of system interconnection (in particular the Anglo-French interconnector given its location on the system) as cross border balancing providers.

- Despite geographical issues a social cost recovery based system is applied with costs recovered on MWh pro rata basis by generators and suppliers. The rationale is that system services provide a benefit to all system users. Furthermore it is a complex task to isolate the causer of system operator actions due to the complexity of network operation and the difficulties experienced in applying the appropriate level of cost in a fair and equitable way, as the services funded from time to time may address more than one system issue.

- The System Operator in GB is the only System Operator in the world that is permitted trade on forwards markets to help provide balancing services (speculative proprietary trading is not allowed). This is highly controversial and will be the subject of review in a forthcoming regulatory review of the role of the GBSO. There is strong pressure for this particular GBSO activity to be prevented as there is a belief amongst many market participants that whilst this may reduce system balancing costs (although this is unclear and thus disputed) it does influence (inappropriately) wholesale electricity prices which in turn have a more substantial impact on consumers.

- Any lessons taken from the GB context for the application of system services in the SEM should carefully consider the relative scale of the GB market, the greater diversity of the fuel mix, and generation ownership and the negative experience of forcing the implementation issue where competition for system service provision is weak or monopolised by a dominant provider, First Hydro being a case in point. We believe Ireland can learn from the evolution process in GB, to meet changing market structures (e.g. generation mix) and operational needs. In this regard we would highlight bidding behaviour patterns post NETA implementation as well as GBSO actions to encourage greater competition between active participants.

10.2 New Zealand

The following points are intended to draw out suitable learnings from the New Zealand review.

- New Zealand has a large amount of hydro generation. This facilitates a co-optimised energy and system services market where the SO does not have serious issues regarding plant operating priority (having the appropriate plant running (or available to run) in operational timeframes). This makes for simpler frequency control and less expensive operating costs i.e. it removes the issues of slow or inflexible plant dynamics which require more advanced planning and coordination of reserve provision.

- On the face of it New Zealand appears to have a high generation margin (c.40%), which in theory should make for a competitive system services markets. However, much of the hydro plant consists of river chain and lake systems with severe environmental restriction on flow which restricts and limits production from time to time. Additionally the availability of conventional thermal plant is sometimes curtailed due to environmental restrictions (cooling water temperatures returning to rivers) which also limits production options.

- The SO has reported insufficient generation margin in recent years. This is the only island studied where the government has subsequently taken direct action following the process of liberalisation and the introduction of competition.

- Hydro systems, which form the majority of New Zealand generation portfolio, are generally located some distance from the main demand centres, particularly Auckland. The nature of the New Zealand network is best described as long and 'stringy' due to island topography and the distances involved. With this in mind the primary concern for the New Zealand TSO is the provision of reactive power to support voltage and power flows on the network.

- New Zealand has no external interconnectors. However, there is heavy use of an internal inter-connector between the two islands (North and South islands) that helps to reduce dependency and cost on an island specific basis.

- System services arrangements in New Zealand today are essentially the same as those developed when the market first opened, reflecting limited change in market structure and generation mix. Payment mechanisms for reserve have changed, with the incorporation of a 'high risk feature' in the event charge.

- Any review of potential lessons from the New Zealand context for the application of system services in Ireland should carefully consider the high proportion of hydro generation that New Zealand enjoys alongside the relatively high level of competition for the provision of system services. This enables easier and cheaper control of frequency leveraging the co-optimisation approach adopted for energy and system services provision. New Zealand, as two islands, also benefits from the ability to use a significant interconnection between the two.

10.3 Tasmania

Possible points of relevance from the Tasmanian review are bulleted below:

Tasmania as an island market with a monopoly generator (may appear similar to Cyprus; see below). However, the Basslink connection with mainland Australia changes the dynamics of islanded operation. Basslink can provide >25% of Tasmania electricity demand enabling competition for the provision of system services to be provided by others producers from the mainstream Australian electricity market. It is therefore possible to successfully implement a viable system services market in Tasmania as the island is, from a power generation perspective, an extension of the mainland Australian market.

- Tasmania has very high levels (>95%) of hydro generation. This combined with the large level of interconnection makes this highly suitable for a co-optimised approach and enables reasonable competition in the provision of system services (specifically Frequency Regulation).

- As Tasmania is a small island the principal focus of service provision is on frequency control. One issue with the interconnector is that at times all frequency control capability is delivered from mainland Australia which can cause frequency deviations. As a result operational changes may be required regarding interaction between the two systems.

- Of the markets studied, Tasmania had the lowest cost per MWh for system service provision due to island size and the level of hydro generation available.

- Any review of potential lessons from the Tasmania context for the application of service provision in the SEM should carefully consider the dominant hydro generation presence on the island and the fact that Tasmania is effectively an adjunct of a much larger market. Furthermore the capacity of the interconnection (as a proportion of island demand) between Tasmania and mainland Australia reinforces the high level of competition for any service provision required. As the island is relatively small and demand is also relatively low, the need for reactive power is also very low. Hence in general the costs of the provision of services are far lower than for an island of the scale of Ireland especially given the comparative mix of generation.

10.4 Singapore

The following points are intended to draw out suitable learnings from the Singapore review.

- Singapore is an isolated system with a high single fuel dependency (gas) which explains its very high plant margin. There is no significant wind generation on the Island and no particular plans for its introduction in any major way in the near or medium term.

- System services arrangements are similar to New Zealand and Australia with similarities in terms of the design of the energy market the operation of regulation and reserve markets. This is really a case of “copycat” market design and does not necessarily indicate it is the appropriate approach. This is reinforced by the fact that regulation costs are unduly high and currently being investigated by the Singapore regulator.

- The Singapore market operates on a “causer pays” principal for reserves (according to the size of the generation load) with part of regulation costs also charged to the first 5MW of each generator. The remainder of the regulation charge and other system services charges are collected from suppliers. It is relatively straightforward to apply the causer pays principle in Singapore due to the simple network topography and small number of generation sites.

- Singapore is the only market that has Black Start procured by an annual auction rather than bilateral negotiations with generators. This reflects the fact that Singapore is the smallest island in this study and it has no geographical network constraints or issues that would otherwise require Black Start capability to be available in other network locations and / or from other interfacing electricity markets. It also reflects the fact there is more than sufficient Black Start capability available locally which in itself provides natural competition for service provision.

- Any review of potential lessons from the Singapore context for the application of system services in the SEM should carefully consider the small size of the island (and thus relative reduction in network issues), and the very high plant margin.

10.5 Cyprus

Possible points of relevance from the Cyprus review are bulleted below.

- Despite liberalisation, the Cypriot electricity market is still a fully monopolistic market with one supplier and one generator.

- The market is obviously in the process of transition with participant limitations where bilateral arrangements are the only feasible way forward for all operational requirements including the provision of system services.

- The small scale of the market (4.7TWh) and lack of interconnection means that unsurprisingly system services come at a high cost when compared to other markets as there are no economies of scale.

- All system services costs are recovered from suppliers on a monthly basis.

- Any review of potential lessons from the Cyprus context for the application of services in the SEM should carefully consider the fact market arrangements have only been recently introduced, and the size of generation is small. It is also the only market studied which has a true monopoly generator and this together with the early stages of market liberalisation means that market regulation and the approach to system services are much different from the other markets studied in this report.

10.6 Spain

Spain provides an interesting contrast from the island markets reviewed. The observations of note are as follows.

- Due to significant government incentives, renewable generation has a significant presence in the overall Spanish generation mix. Renewable generation (including conventional hydro power plants) accounted for over 50% of the installed capacity in 2010. This increase in the relative share of renewable output was achieved primarily due to the growth in wind generation (which grew over 30% since 2007) and solar PV output (increased almost 15 times since 2007). Hydro generation with over 19GW of install capacity accounts for 20% of Spanish production and plays a significant role in ancillary service provision. It is worth highlighting the fact that Spain is unique among the markets studied in that it is not a true island and it already has interconnection with mainland Europe. This may somewhat limit its comparability to the SEM (e.g. primary reserve is less of an issue).

- The Spanish market is a large electricity market with well-developed networks. It is significantly larger than the Ireland market and has a high spend (€593m) on system services. Over 50% of the system adjustment service goes on solving technical constraints which is a level not seen in any other country covered by this report.

- Interconnection between Spain and mainland Europe is limited. The current interconnection capacity with France is around 1.5GW (3% market). Significant increase in interconnection capacity and the introduction of a more effective market design are needed to better integrate Spain and the Iberian market with France and rest of the Europe. New interconnection capacity with France is in the planning stage at present where greater interconnection will ensure better future management of volatile renewable generation.

- The system services market in Spain hasn't changed significantly since 1997 when the market was first liberalised. Most of the services are provided by the spot market and some (voltage control) are procured via bilateral contracts.

- Any review of potential lessons from the Spanish context for the application of system services in Ireland should carefully consider the size of the market, fuel mix diversity including the significant presence and availability of hydro generation. However Ireland can learn from significant real time operation experience of a system that incorporates high variable generation penetration and limited interconnection.

11. Characteristics of individual system services

11.1 Frequency Regulation

The following characteristics of Frequency Regulation should be noted:

- In all markets, there is a mandatory requirement for generators to have the capability to provide a defined level of frequency regulation which is enforced by the relevant technical Grid or Network Code. However, in all markets the use of Frequency Regulation is procured commercially with generators paid as bid for the service, reflecting the value to the System Operator and/or opportunity cost of the generator.

- Some markets procure enhanced Frequency Regulation services where frequency is especially sensitive/volatile e.g. in GB both the enhanced capability and enhanced payment terms are applied on a commercial basis.

- Singapore has comparable arrangements to New Zealand and Australia. However, the different generation mix has resulted in high costs for this service in Singapore.

- The “causer pays” principle for Frequency Regulation has been implemented in Tasmania and partly in Singapore.

- GB has started to see an increasing focus on Frequency Regulation due to the emergence of more wind generation on the network. There is much less wind generation in GB than in Ireland, where there is likely to be a more significant issue on managing frequency and procuring necessary services economically.

- A value based Frequency Regulation market was recently introduced in GB. Due to limited competition for provision (in terms of generation owners) and arguably a distressed buyer situation, the result was that costs doubled without any benefit to system operation.

11.2 Reserve

The following characteristics of Reserve are worthy of note:

- New Zealand, Tasmania and Singapore all co-optimise Reserve with the energy markets. In the case of Tasmania and New Zealand this is facilitated by the large amounts of hydro generation which makes such an approach practical. In Singapore it is seemingly a case of copying the New Zealand/Australian arrangements which although does not satisfactorily fit with the generation mix in Singapore, can work due to high plant margins, high relative reserve levels needed and the relatively large generation unit capacity compared to island demand.

> GB has a mixture of market arrangements for procurement of reserve and non-tendered bilateral contracts for reserve. This is to give National Grid flexibility in obtaining the necessary types of reserve needed by the system (at the most economic cost) by facilitating market forces where competition is high and controlling information and cost mechanisms where competition is low.

> GB has started to see a greater focus on reserve due to the emergence of increasing amounts of wind generation on the network. There is much less wind generation in GB than in Ireland, where there is likely to be a more significant issue on managing reserve and procuring the necessary services economically.

> Cyprus has a bilateral only market for Reserve, which reflects the monopoly nature of its generator.

> A mixture of “causer pays” and socialisation of the Reserve costs is being used in different markets.

11.3 Reactive Power

The following characteristics of Reactive Power have been observed in the review:

> In all markets, there is a mandatory requirement for generators to have the capability to provide a defined level of Reactive Power and this is enforced by the relevant technical Grid or Network Code. As well as this, in all markets the utilisation of Reactive Power is procured commercially with generators paid for the service, reflecting the value to the System Operator and/or opportunity cost of the generator.

> Generally reactive power is of lower importance and cost than frequency control on an island network. This will vary depending on the size of the island (and thus network) and the location of generation and demand (thus nature of power flows).

> In particular, Reactive Power is of low importance for smaller scale markets where network sizes (and line distances) are also limited and power flows are proportionally quite small. Singapore is sufficiently small in size and has relatively local collocated generation and demand centres such that Reactive Power requirements are minimal and costs are proportionally minimal.

> For larger scale islands especially with longer network routes and/or geographical disparity of generation sites and demand centres, Reactive Power can be a more important service to the SO. This is the case in both GB and particularly New Zealand which have very long network routes.

11.4 Black Start

The following characteristics of Black Start should be noted:

- In most island markets there are bilateral contracts for the provision of Black Start. This is due to the need for a geographic spread of these services in reasonably sized networks with potential constraint issues to address; thus the need for the TSO to specify and/or control the location of such service providers.
- Accordingly Black Start is typically compensated by the SO paying on an annuitised basis the capital costs for construction of the Black Start facility. Typically utilisation including any testing is not paid for under contract if the Black Start facility can recover this via the wholesale market (e.g. coordinate the test in a way which allows market selling). Furthermore typically a Black Start facility is free to participate in the energy market if the owner feels it economic to do so.
- The exception in this study is Singapore which procures Black Start via a regular auction. This is due to the small island nature of Singapore and the collocation of power plants and load centres that removes many of the network issues identified elsewhere. More than sufficient Black Start capability is available in this market making it a viable area for competitive service provision.
- Black Start is a relatively small proportion of system services costs. As an example Black Start services in the GB account for around 3% of system service costs.

12. Key observations

This section draws together some final key observations from the review and compares the operation of the different island electricity markets and the approaches adopted in relation to the provision of system services. The key points are as follows:

(i) **Relative market size of system services to wholesale energy** – in all markets wholesale energy is by far the largest component in relation to consumer costs and generator revenue streams and it is a primary factor when designing (and redesigning) wholesale and system services market arrangements. Clearly the primary importance is to ensure the wholesale energy market operates effectively and is not undermined and/or polluted by the design of the system services arrangements. Equally it is important that the secure operation of the system is not undermined by system services arrangements which are overwhelmed by wholesale energy market incentives due to unforeseen market incentives and associated participant behaviour. This is typically why system services arrangements have not been radically changed during periods of wholesale energy market reform, but have instead evolved separately over time.

(ii) **System services market size** – the absolute size of the overall market for system services is an important consideration in designing regulatory and commercial arrangements for service provision. There is little point in designing complex diverse arrangements to address system services where costs are relatively low in absolute terms, and it is unlikely to be cost effective to do so. This is why GB is the only market of those studied to apply complex operating arrangements and to have in place SO cost incentivisation in relation to the procurement of the services required.

(iii) **Generation mix** – the mix of different types of physical generation is very important is designing system services arrangements. High presence of hydro for example enables approaches to be adopted which otherwise would be non-viable from a secure system operation perspective. Furthermore, high levels of variable wind generation introduces much greater challenges for system operation and greater need for certain key system services than where wind represents a small share of overall generation capacity. GB is already seeing increasing difficulties posed by a higher incidence of wind generation; but even so it faces much less proportionate wind capacity than Ireland and Northern Ireland. In short system services arrangements must take account of the generation mix and its impact on system operation.

(iv) **Market power** – the degree of active competition available to deliver the required services is of key importance when considering the development of system services arrangements. Where market power is shared (high levels of competition), market mechanisms are shown to operate effectively as procurement tools for services; and information transparency on the part of the SO can be high. Where market power of one or a few incumbent generators is high (low levels of competition) typically bilateral based procurement approaches are adopted and information transparency is restricted to avoid unduly high costs to the consumer. In the latter situation the SO is not necessarily prevented from seeking to contract with new providers (as they become available) and ultimately seek to evolve to a more dynamic market mechanism. However, experience shows that premature implementation of a market where strong market power exists (individually or collectively) gives rise to artificial market conditions which generally deliver little, or at best, limited benefit to participants and/or end users.

(v) **Interconnection –** an important aspect in considering system services arrangements is the degree of interconnection with other markets. The high degree of interconnection of a large regional system as that covered by the UCTE in Europe, is primarily the reason why frequency control within the UCTE represents a far less onerous issue than for island systems. Islands with relatively low interconnection require a strong focus on the robustness of frequency regulation arrangements. Islands with relatively high interconnection capacity may have a lower focus on frequency regulation and will have access to greater competition in service provision, as long as market arrangements either side are compatible. This is why Tasmania is able to utilise its interconnector to great effect and why in New Zealand the North-South Island interconnector plays a key role. For GB the different market arrangements in continental Europe have prevented (to date) full use of the Anglo-French interconnector (for system services) though this is now being developed due to the highly changeable interconnector flows and the consequent impact on system operation in GB.

(vi) **Cost recovery** – apart from (i) very simple and/or small network examples where incentivisation on performance to reduce system service need is important, and/or (ii) the clear identification the 'causer' and the costs attributable to that causer are clear, the general philosophy has been to socialise the recovery of system services costs, recognising that they provide benefit to all users of the system. Some markets have sought to target generators as a community for creating certain system services needs (i.e. Frequency Regulation and Reserve) but it is debatable whether this approach is appropriate given that demand can usually drive similar if not equivalent needs for these services.

(vii) **Evolution of system services** – for markets where there is little dynamic in the generation mix, generation ownership, market rules and/or market behaviour there is little need to change system services arrangements. This is evidenced, for example, in New Zealand. For markets where there is clear dynamism and change taking place (participants, structures and behaviour) it is natural to expect positive evolution to occur. This has been the case in GB. Ireland is expected to see substantial change in market dynamics as the generation mix changes over time, so it would therefore seem appropriate that system service provision should evolve over time. However, as evidenced elsewhere it is important not to prematurely introduce change for changes sake. In KEMA's opinion it would be unwise to implement seemingly future proof solutions in markets that do not support the levels of competition necessary to bring about effective and economic provision.

13. Summary and Conclusions

This final section sets about summarising the outcomes from the study and provides the key conclusions from the country review of the services adopted by the international electricity markets studied in this report. This is addressed from three different perspectives as follows:

> General observations and conclusions which arise from the overall review of the six markets selected and the relevant points worthy of note in the context of current service provision in the SEM;

> Key (individual) observations for each electricity market and how (if appropriate) the services relate to the All Island market; and

> A summary of observations and conclusions for each category of service (i.e. Frequency, Reserve, Reactive Power and Black Start) together with relevant points to note in the context of service provision in the SEM.

13.1 General Overview

A number of overall observations can be made from reviewing the treatment of system services across the six markets (GB, New Zealand, Tasmania, Singapore, Cyprus and Spain) reviewed in this report. These are as follows:

> All of the markets have mandatory requirements on large generators to ensure they have the capability to provide the necessary key service requirements, namely frequency regulation and reactive power provision. In each market this capability and the level of technical performance mandated is enforced by conditions under the relevant technical Grid or Network Codes. However, whilst the capability to provide these core system services is mandatory, in all of the markets it is accepted that service providers incur a cost (real or opportunity) of provision, and as such need to be rewarded for delivery. Furthermore all markets set service payments on a commercial basis. It is also important to ensure that appropriate performance is delivered, and that there are provisions made for provider contracts to penalise poor performance. This approach is uniformly applied across all markets and is seen to best ensure capability, availability, performance and timely delivery of the services sought by the SO.

> The prevalence and effectiveness of ancillary services markets strongly reflects the number of potential providers (in terms of generation companies). The most effective markets are those where the specific service required can be provided by a number of different participants giving rise to active competition for the provision of such services to the SO.

- Some system services are fully procured via a pre-determined market mechanism, others jointly by bilateral contracts and the remainder remain solely bilaterally contracted. There is not necessarily any rule or system that determines which procurement method is most efficient. As an example when NGC were driven by Ofgem to establish a market for frequency regulation, the GBSO found the costs of service provision almost doubled. A number of subsequent market modifications have been implemented to address this with limited success. At this point it is also worth highlighting the trade off noted between the level of sophistication employed to procure the provision of services and the level (transparency) of market information that flows as a result. Essentially market information (granularity and transparency) decreases as competition decreases.

- Out of all six markets only Spain has a significant market share of variable wind generation comparable to that in Ireland and Northern Ireland. Whilst GB will see a strong increase in wind generation in the next 10 years it will still not proportionately match the levels to be seen in Ireland and Northern Ireland; furthermore it is counterbalanced by a greater diversity of other flexible plant ownership. At the opposite extreme both New Zealand and Tasmania have a majority share of hydro (>95% for Tasmania), so it is important to recognise that this further eases system operation in real time but also enables less forward planning and contracting of system services than would otherwise be needed. It is therefore very important to take account of the generation mix when considering the appropriate system service provision in the SEM. The Spanish dynamic may, therefore have more relevance to the future operation of the all Island system in terms of future system service provision.

- A number of the markets have high generation margins. This should assist in the plants that can be made available and therefore the competition that should exist for the provision of the services sought. Whilst the plant margin in Ireland may appear high, when adjusted for performance (e.g. intermittency of wind generation and reliability of older fossil fuel plant) it is in fact relatively low.

- System services markets are generally a relatively minor consideration in the context of the broader wholesale energy market. Investment in complex mechanisms to minimise these costs is therefore often overlooked on a straight cost/benefit basis. Whilst it remains true that wholesale energy market revenues dominate the considerations of generators as a whole, in the GB market the absolute scale and cost of the system services requirement means that it attracts regulatory focus which has lead to provider incentivisation to minimise provider cost. The consequence of this has been the steady development of a diversity of complex arrangements for both individual system services and the portfolio management of services in the GB market as a whole.

- Those countries that are interconnected do attempt to use the interconnectors to provide system services on a commercial basis. In particular GB is actively seeking to develop cross border service provision via existing (and forthcoming) interconnectors to help increase competition for services and to address the impact of increasing amounts of variable wind generation on the network. Consequently, given the large and growing proportion of wind generation in Ireland it may be useful to note the GB initiatives and consider (as Ireland expands its level of interconnection) the merits of exploring the potential opportunity to expand the competitor base for ongoing service provision.

- As a general rule all of the markets essentially socialise the cost recovery for the provision of most system services. New Zealand, Tasmania and Singapore do seek to target recovery of reserve costs and some frequency costs to the 'causing' generators to incentivise appropriate technical performance (i.e. reliability) due to the impact that poor performance can have on their system; but also because it is relatively straightforward to identify the causer of frequency regulation and reserve actions. The thinking is that the impact is sufficient to merit active incentivisation to reduce the number of occurrences and thus the need for system services requirements by the SO. From a cost recovery perspective, service costs are generally socialised in recognition that system services provide a benefit to all network users, and underlining the fact that identifying the 'causer' in larger more complex networks can be a difficult and costly process.

- For most system services across most of the five electricity markets studied, different variants of social cost recovery are applied (e.g. customers pay all pro rata on MWhs delivered, or costs may be levied on both generators and customers). This is because in the main the view is that the provision of system services provides a "social" benefit to all in any given supply community. In the Asia Pacific markets there are some examples of causer pays situations for frequency control - either broadly to the generator community (as in New Zealand and Singapore) or to individual generators (as in Tasmania). The former approach represents a broad brush view that the service need is driven by generation (which is not strictly correct as demand can drive the same need) whereas the latter approach is only possible due to the simplicity of the network and relative ease with which 'causers' can be identified and costs can be attributed. Whilst in principle it may be desirable to encourage greater reliability of generators where they can have a more significant impact on the network, for more complex networks and markets with greater mix of system services requirements it is both difficult and financially inefficient to apply this approach.