Electricity Supply Industry Expert Panel

Technical Parameters of the Tasmanian Electricity Supply System

Information Paper

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1. Objectives and Structure of this Paper

The objectives of this paper are to explain for the lay person some of the unique physical features of the Tasmanian electricity supply system and the way these features influence the way the system is operated, the impacts on system security requirements and the contributions these make to the cost of supply. It considers in particular, the impact of the most recent infrastructure additions to the system including Basslink and Tamar Valley Power Station, as well as National Electricity Market (NEM) participation. The paper does not deal with commercial matters related to the sale or purchase of electricity except where it is necessary to explain features of an operational activity.

Chapter 2 of the paper is primarily for those readers who are less familiar with the principles of electricity generation and supply or wish to ensure that their understanding of the terms used is consistent with those of this paper. Chapter 3 is also of a general nature and introduces the more important issues involved in the operation of an electricity supply system and the maintenance of electricity supply continuity. Chapters 4 to 7 describe some of the key characteristics of the Tasmanian electricity supply system, the manner in which it is managed, and the impact of recent changes including mainland interconnection and the commissioning of modern thermal generating facilities. Chapter 8 considers some of the future issues that may be faced by the electricity supply industry in Tasmania and in particular, the impacts of an increasing focus on renewable energy technologies.

Where practicable, this paper will not repeat the information provided in papers which have already been developed by the Electricity Industry Panel Secretariat. Readers may find that familiarity with the paper entitled '*Tasmania's Energy Sector – an Overview*' is useful.

2. Principles of an Electricity Supply System

2.1. Introduction

The electricity that is used for most industrial, commercial or domestic purposes is required to be generated at the time of use. (Storage in batteries is possible but the cost is currently prohibitive except for remote locations that do not have access to an interconnected system)

The electricity generated for contemporary systems is termed **alternating current** (**AC**) and its polarity (the direction of current flow) cycles 50 times per second. The number of times the polarity changes from positive to negative in each second is termed the supply **frequency.** All systems generating electricity for general consumption in Australia operate at 50 cycles per second (cps). Some variation in frequency is allowed to provide some operational flexibility and this will be discussed in some detail later in this paper. In some regions of the world, different frequency standards apply (the USA uses 60 cps) and equipment designed for that standard (such as electric motors and some household appliances) may not be suitable for use in Australia.

Electricity is transferred from one place to another via a **conductor**. Conductor materials in common use are copper and aluminium as they have low resistance to the passage of electricity and may be formed into suitable conducting cables at reasonable cost. Materials which do not conduct electricity are referred to as **insulators**. Conductors which are in the form of wire (or cables) need to be insulated to contain the electricity and ensure its safe use. Air is a reasonable insulator and is therefore used as the insulating medium for overhead electricity wires.

One of the identifying properties of an electricity supply is the voltage at a particular point in the supply chain. There are other important identifying properties and these are dealt with later. Voltage can be considered analogous to the pressure of a water supply. Electricity at high voltage requires a higher level of insulation to ensure it may be conducted safely, however a conductor operated at higher voltage can transfer greater amounts of energy more efficiently as will be demonstrated later.

Alternating current electricity is used because it allows for voltage to be increased or reduced via a **transformer** which aids the efficient transfer (or transmission) of electricity from one place to another. An alternating current supply is also more practical when used to provide the energy to electric motors.

Direct current (DC) which is supplied by a battery or a direct current generator is associated with positive and negative connections and current flows from positive to negative. It is possible to convert alternating current electricity to direct current electricity via a **rectifier**, or convert direct current electricity to alternating current electricity via an **inverter**.

Most electricity is produced in rotating machinery called a **generator** (the term generator applies to either AC or DC machines, but AC machines are often referred to as **alternators)**. Examples of the sort of rotating machinery used to drive generators include conventional combustion engines (like those in a motor vehicle), gas turbines (similar to those that power modern aircraft), steam turbines which use steam generated in a boiler (or other source) to drive a rotating shaft, hydro turbines (which convert the energy in moving water to rotational energy), and wind turbines which utilise the energy of the wind.

Electricity can also be generated in solar cells which convert solar radiation into electricity by the use of photo voltaic or photo electric cells. The electricity so formed is direct current electricity and needs to be inverted before it can be used in most commercial applications.

2.2. Properties of Electricity

Nearly all utility electricity supply systems are based on the provision of an alternating current, **three phase supply**. The three phases result from the manner in which the conductors in a generator are arranged and interconnected. A three phase configuration allows for smoother and more efficient generation, with similar advantages when used in larger electric motor drives. It provides for smaller conductor sizes within the generator or motor and greater power to weight ratios overall. The majority of distribution systems provide a choice of three or single phase power supply; however the majority of domestic consumers have a single phase supply.

The amount of electricity flowing through a conductor, and referred to as an electric current, may be considered analogous to the amount of water that flows through a pipe and is measured in amperes or **amps.** The current that may be transferred through a particular conductor is determined by the size of the conductor, the length of conductor through which the electricity is transferred, the material from which it is made, the voltage of the supply and other characteristics which are less important. The property of a conductor, which takes into account the parameters above, and reflects its ability to transfer electricity, is termed its **resistance.** The selection of conductors for commercial electricity transfer systems is a compromise between low resistance and low cost.

The instantaneous measure of the power of an electricity supply to a consumer, or the ability of that supply to do useful work is measured in **watts.** Because a watt is a relatively small unit of power it is common to measure power in multiples of 1000 watts (kilowatts kW), or megawatts (MW), 1 million watts. If such a supply is maintained for a period of time the total energy consumed is the product of the power and the time for which it is utilised. It is common practice to measure energy flow in **kilowatt hours** (kWh). Larger quantities are measured in **megawatt hours** (MWh) or 1000 kWh, or **gigawatt hours** or 1 million kWh.

The total demand for power from an interconnected electricity supply system is the sum of the instantaneous requirements of all consumers and is referred to as **system demand**. The manner in which system demand varies according to the time of day and to seasonal conditions is discussed later.

An alternating current electricity supply does more than simply provide energy. Many devices that utilise electricity, such as electric motors, depend on the development of a magnetic field for their operation. The development of these magnetic fields requires the passage of electric current that itself is not responsible for the consumption of electrical energy or provision of useful work. In the process, this so called **magnetising current** component (referred to as **reactive power**) appears out of phase with the current that essentially provides the energy required by the device. The result of combining these current components is a net current that is out of phase with the voltage of the supply. The mathematical relationship defining the extent to which the net current is out of phase is referred to as the **power factor** of the device. The provision of reactive power results in a lagging power factor. Under some circumstances, such as when a transmission line is very lightly loaded, the power factor may in fact be leading.

In simple terms, provisions must be made to meet the **reactive power** requirements of an electricity supply system or adjust the supply in the opposite direction when the power factor is leading. This is achieved by adjusting the parameters of operating generating plant or when generators are located some distance from the load centres as is the often the case in Tasmania, by reactive support devices. Power factor can be corrected by static var compensators (SVC's) or dynamic devices such as synchronous condensers. Dynamic devices are not currently being used in Tasmania but may prove to be necessary in the future.

2.3. Generation

As previously discussed, most electricity is generated in rotating machinery driven by a range of prime movers.

In Tasmania the majority of generators are driven by hydro turbines. Hydro turbines are classified into two main types depending on the way in which the energy is extracted from the water flowing though the turbine. **Impulse turbines** rely on directing a high velocity jet of water from a nozzle or nozzles, at a rotating wheel of buckets which are mounted on the turbine shaft. Such turbines are usually associated with high pressure (or head) water supplies and are referred to as **Pelton** turbines after one of the early developers of these machines. The other main type of turbine is called a **reaction turbine** and relies on water flowing through specifically shaped radial blades for its operation. **Francis** turbines and **Kaplan** turbines are two reaction turbine types in use in Tasmania and are used on medium and low head applications respectively. The infrastructure required to collect, store and deliver the water supply to hydro turbines is often extensive and includes dams, tunnels, ducts and high pressure conduits. Collectively all the infrastructure elements that are part of a particular project are referred to as a **hydro electricity scheme**.

Hydro electric schemes involve high capital costs but have low ongoing energy supply costs.

Nearly 80% of Australia's electricity consumption is provided by generators driven by steam turbines. The steam utilised in these turbines is produced in a boiler at high pressure. Boilers can be fired with a variety of fuels including coal, gas, oil, wood or even combustible waste. The majority of Australia's steam turbine plant is provided with steam from boilers fired on coal. Steam turbine plant also has a high capital cost, although usually lower than hydro schemes, and requires an ongoing supply of fuel. Coal fired steam turbine plant in service today has an energy conversion efficiency of between 35 and 40%. The cost of acquiring coal varies considerably and depends on quality, mining costs and the location of the mine relative to the power station.

The drive towards improving energy utilisation efficiency and reducing capital cost has resulted in development of gas turbines as a common prime mover for electricity generators. Industrial gas turbines used for electricity generation are similar to the jet engines which power modern aircraft, but are packaged in a manner more suited to an industrial environment. The basic components of some gas turbines packages are in fact the same as those used in aircraft and are termed **aero derivative gas turbines**. Gas turbines developed and manufactured specifically for electricity generation or mechanical drives are referred to as **industrial gas turbines**.

The components that make up a gas turbine consist of an air compressor, a combustion chamber (or chambers) in which a fuel is burnt and the compressed air heated, and a turbine through which the hot gases are expanded. The expanding gas stream imparts energy to a turbine shaft which is used to drive a generator. After passing through the turbine the gases which are still hot are either exhausted to atmosphere or further utilised. Gas turbines which exhaust gas to atmosphere are termed **open cycle gas turbines**. Either liquid fuels or gas may be utilised in gas turbines. Open cycle gas turbine generating plant costs range from 25 to 35 % of traditional steam turbine plant. Open cycle gas turbines have energy conversion efficiencies of between 30 and 35%. The relatively low capital cost of open cycle gas turbine plant has resulted in these units often being installed for meeting short term peak loads. Also a consideration is the relatively small "foot print" of this type of generation equipment, allowing its installation in locations where land availability may be restrictive for whatever reason.

To utilise the heat in the exhaust gas coming from an open cycle gas turbine, the gases are passed through a waste heat boiler or heat recovery steam generator, and the steam so produced is fed to a steam turbine. The steam turbine is then able to drive an additional generator. Such an arrangement is called a **combined cycle gas turbine**. Combined cycle gas turbine installations costs tend to be around 50 to 70 % of traditional steam turbine plant and have energy conversion efficiencies as high as 53%.

Small scale electricity generation systems are generally driven by reciprocating combustion engines which may be fuelled with petrol, distillate or gas. Such systems are usually remote from other sources of supply and typically service an island or a remote inland community.

Apart from hydro turbines, the most economically attractive renewable source of electrical energy is wind generation. A range of wind turbine configurations have been trialled over the last 30 years with varying success. The most common application now consists of a three bladed hub which drives a generator through a gearbox to increase shaft speed. The turbine shaft gearbox and generator are all mounted in-line on a rotating platform mounted at the top of a tower. Control devices are generally provided to ensure that the turbine is positioned according to wind direction and the blade pitch optimised to the prevailing wind speed. New wind turbine technologies continue to emerge with ever increasing efficiency statistics and available power ratings. Common wind turbine ratings for on-shore applications are now between 2 and 3 MW, with hub diameters of up to 112 meters. Wind turbines are rated according to their output at the optimum wind velocity for which the unit has been designed. Output of the turbine at less than optimum wind velocity is of course lower than rated output. The **capacity factor** of a wind turbine is the fraction of the energy that can be produced for a particular wind regime compared with the energy which could be produced if the wind where to blow continuously at the optimum wind velocity.

The fastest growing form of renewable energy, albeit from a low base, is that of **solar photo voltaic** (solar PV) cells systems. The electricity generated is direct current and may be used to charge battery systems or be inverted and used to power domestic or commercial appliances. Recent incentives by governments internationally to increase the application of solar PV cells, has stimulated the market and resulted in more efficient cells being developed at reduced manufacturing costs. Australian Government capital incentives, and attractive feed-in tariffs offered in some states, have encouraged the installation of grid connected domestic installations.

Electricity is also generated by a number of other renewable technologies including geothermal, solar thermal, tidal and wave power. Some of these technologies have been utilised for limited commercial applications but are yet to be developed to the point where they are widely accepted as alternatives for grid interconnection. Many renewable technologies are by their nature unable to be relied upon for the continuous supply of electricity because of the variability of energy input. Wind turbines fall into this category. Such technologies are referred to as intermittent and require alternative sources of generation to be available to ensure continuity of supply.

A summary of the principle generating technologies is provided in Table 1 below

Table 1 - Summary of Generating Technologies

Generator Type	Capital cost $/MW installed	Marginal operating cost fuel plus O&M $/MWh	Start up time from cold hours	Potential capacity factor %	Contribution to system inertia
Conventional Steam	2 million	50	4	90	good
OCGT	0.6 million	80	0.25	93	fair
CCGT	1.2 million	60	0.25 to 1.0	90	fair to good
Hydro	2 - 4 million	10	0.03	95	good
Wind	2 million	10	0.02	40 (max)	poor
Photo Voltaic	8 million	5	0	25	poor

Note that costs are indicative and are provided for comparative purposes only. The capital cost of hydro is location dependant given the significant civil infrastructure requirements.

2.4. Delivery Elements

Electricity is frequently generated in an area remote from the point at which it is used. The transfer of bulk (or large quantities of) electricity to consumers usually occurs via a high voltage **transmission** network. The voltages at which transmission networks are operated vary according to the quantity of energy to be transmitted and the distance from the generator to consumer. Voltages currently used in Australian transmission networks vary between 66,000 volts and 500,000 volts (66 kV and 500 kV). In Tasmania the transmission network operates at voltages of 220 kV and 110 kV which reflect the magnitude of the energy transfer requirements, and distances over which the individual transmission lines travel.

When electricity is transmitted to an area of consumer use, its voltage is reduced using transformers and associated switching devices in a **substation**. From the substation, electricity is reticulated to consumers via a **distribution** system. Because distribution systems need to be located in close proximity to human activity, they operate at lower voltages. Distribution systems typically operate at 22,000 or 11,000 volts for the back bone of the system, and 415 volts for the electricity wires that run along the street and into homes and businesses. Tasmanian low voltage distribution systems are mostly run on wooden or steel poles but may also be run underground, especially throughout city areas.

The voltage of electricity supplies to most homes and smaller commercial consumers is single phase 240 volts. Larger business and small industrial sites may be connected to a three phase supply at 415 volts to cater for higher energy supply needs. Specific customers consuming even higher amounts of energy may be supplied directly from the distribution backbone at 11 or 22 kV and have their own substation for reticulation of power at lower voltages as required.

The consumption of electricity is **metered** by a device which measures the electrical energy delivered to the consumer's premises. It is purpose built to take into account the nature of the supply including the voltage, number of phases etc. New meter technologies based on digital electronics (compared to the older rotating disc type meters still prevalent throughout Tasmania) allow for greater flexibility including time of use charging, separate feed-in tariffs for embedded generation and demand side management capabilities. "Smart grids" of the future will be dependent on technologically advanced meters at the point of energy consumption to provide both control to the system operator as well as information to the end user.

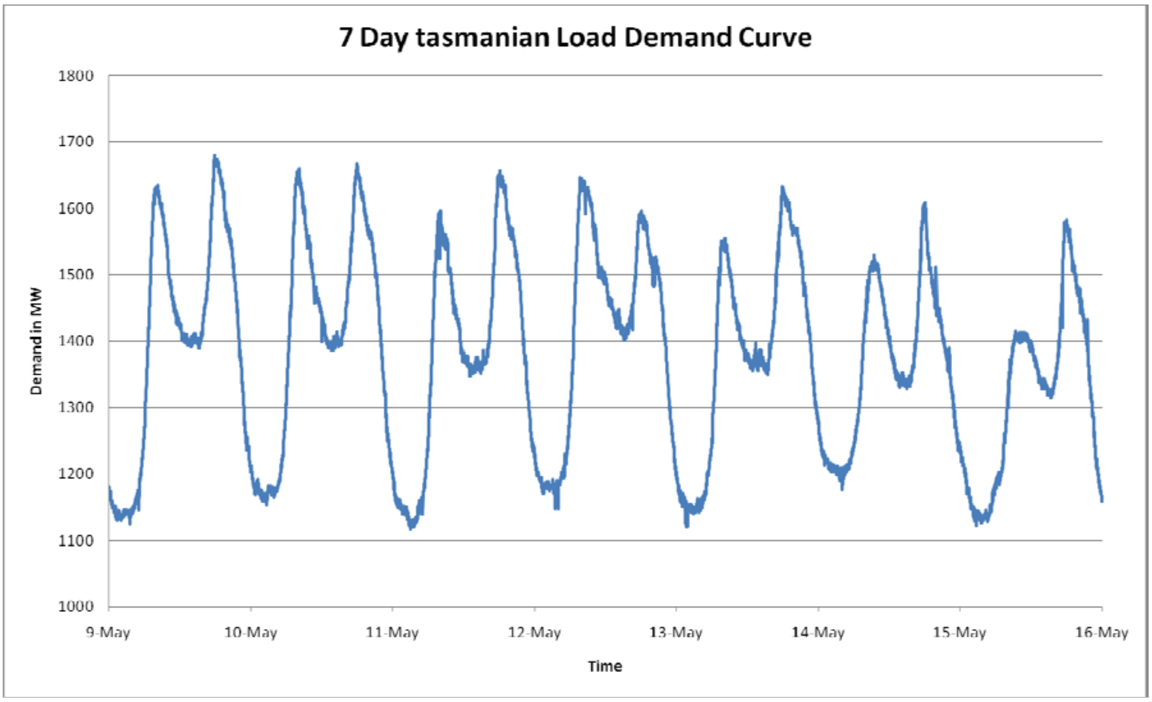
So far, three distinct functions in the electricity supply chain have been discussed being generation, transmission, and distribution. A fourth, that of liaising with the consumer and arranging the various commercial activities (including billing arrangements), supplements the more technical functions and is termed the **retail** function.

3. Technical Issues of Meeting Demand, System Reliability & System Security Requirements

3.1. Demand

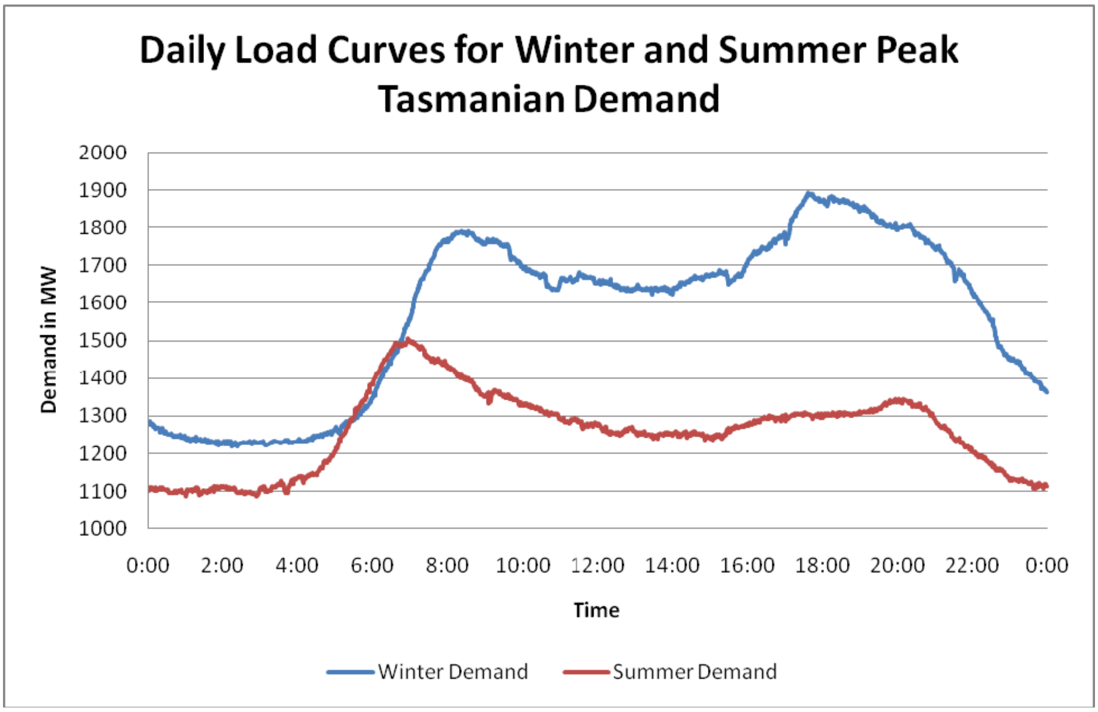
The use of electricity has increased in recent times to now encompass nearly all aspects of domestic, commercial and industrial activity. The sum of all of consumers electricity requirements connected to a particular system at any point in time is termed the **instantaneous demand.** Demand varies throughout the day and also varies according to the time of year. The variation of demand during the day is influenced by domestic and commercial activity which tends to be concentrated at the beginning of the work day and again in the evening, when electricity consumption for lighting, cooking and heating increases. In warm climates, the **peak demand** or maximum demand for the year usually occurs on a summer's afternoon and reflects the increased requirement for electricity to power air-conditioning and refrigeration facilities. In cooler climatic zones like Tasmania, the peak demand usually occurs in winter reflecting an increased requirement for heating. The demand is measured in MW. Figure 1 below shows the variation in demand over a typical winter week. Note that lower weekend demand reflects a reduction in commercial and light industrial activity. Figure 2 shows how the daily maximum demand varies throughout the year.

Figure 1 - Tasmanian Typical May Weekly Electricity Demand



Source: Transend Networks

Figure 2 - Tasmanian Daily Electricity Demand - Summer and Winter Peak Days



Source: Transend Networks

In a system where the instantaneous demand is exactly matched by the sum of the output of all of the generating plant (including an allowance for any system losses), the frequency of the system will remain constant at the desired level (50 cps). In the event that there is a small mismatch where the demand is greater than the sum of the generator outputs, the frequency of the system will fall. On the other hand, if the demand is smaller than the sum of the generator outputs, the frequency of the system will increase. As a result, changes in system frequency can be used as a measure of whether generation is equal to demand or not. The rate at which the frequency change occurs can be used as an indication of the magnitude of the mismatch of demand and generation.

Most generators are equipped with **speed governors** which are a control device sensitive to changes in network frequency. A speed governor will act to increase the output of a generating unit when frequency falls, and reduce the output when frequency increases. In practice, the task of maintaining frequency is usually allocated by the system operator to a nominated group of generators. The allocated generators are selected on the basis that they have the capability to either increase or reduce their output to balance the system's **instantaneous demand** requirements.

The task of predicting what the demand on a system will be throughout the day, and determining which generators are required to be in service to meet that demand, is the task of the **System Operator.** The system operator attempts to schedule generators to be in service in a manner that minimises the overall cost of operating the system. The system operator also has to make provisions for all things necessary to ensure that the system will remain safe and secure. This task will be discussed in proceeding sections. Now that Tasmania has become a participant in the National Electricity Market (NEM), the Australian Energy Market Operator (AEMO) is the system operator for the Tasmanian region. Transend Networks, as the local Transmission Network Service Provider (TNSP), is allocated certain responsibilities to assist AEMO with its day-to-day operational activities.

3.2. Reliability

The continuity of electricity supply to consumers depends on there being adequate generating equipment, transmission and distribution facilities installed and available to meet the demand of electricity at all times. The extent to which this is achieved is a measure of the systems overall **reliability.** It is also essential that an electricity supply system be operated in a safe and secure manner. An explanation of how system **security** is achieved is provided later.

It is usual for the assessment of power system reliability as it relates to the generation and the bulk transmission system, to be separated from assessments that relate to distribution networks. While the reliability of distribution networks is an important issue for electricity consumers, it will not be addressed in detail in this paper.

Traditionally, reliability standards were based on **input based** measures. Generation **reserve margins** (that is the extent to which installed generating plant is in excess of expected maximum demand) and fault tolerance criteria for network design were commonly applied. However, generation reserve margin only provides a guide to the prediction of system reliability.

Reliability is impacted not only by the total generation capacity available (compared with peak demand) but also by the size, characteristics and technical performance of generating plant in question. A power system consisting of many small generating units is inherently more reliable than one with several large units as the failure of a single small unit has less impact on the system. Units with fast start capability are favoured in terms of system reliability over units that require a longer start up time. Units that have high **availability** (i.e. are available for use for a high percentage of time) are favoured over units that have lower availability (units may have lower availability because they are required to be out of service for maintenance for extended periods, or are prone to forced outages due to component failure). The nature of the system requirements in terms of its variation in daily and seasonal demand also impacts on reliability considerations.

The availability of hydro electric generating plant, and therefore its reliability, is also influenced by the availability of primary energy (water). The variability of water inflows in Tasmania has historically been more significant than generation capacity as a determinant of supply reliability.

Methods of statistically assessing the impact on an interconnected power system of the variables mentioned above have been developed progressively over the last 35 years to provide **outcome based** reliability measures. The calculations tend to be complex, probabilistic, and highly iterative. Proprietary software has been developed to support the calculations. **Unserved Energy** (USE) and **Loss of Load Probability** (LOLP) are two of the outcome based reliability standards that have been used in Australia.

While outcome based reliability standards may more accurately reflect system characteristics and risk profile, they are less suitable for defining operational requirements. For this reason minimum reserve levels (calculated in the process of determining the output based measure) are used by AEMO as the means of ensuring system adequacy.

Unserved Energy (USE) is the current reliability standard applied in the NEM and is set at 0.002 per cent of unserved energy. It is effectively an assessment of the long term average of the energy not expected to be supplied when demand exceeds available capacity, divided by total energy required to meet system demand, expressed as a percentage.

In applying the criteria to Tasmania, a USE of 0.002 percent would result in a long-term average of about 200 MWh per annum being assessed as being unable to be supplied.

3.3. Security

Security of a power system is generally defined as the system's ability to withstand sudden changes in demand and the ability to recover from unexpected disturbances (such as short circuits or unexpected disconnection of transmission or generation equipment). The security of a particular system is influenced by a number of factors inherent to the system in question. Two of the more important factors which influence system security are frequency and voltage control capability. The availability of sufficient capability to compensate for unexpected changes in the power system is paramount if system security is to be adequately managed. System security is generally assessed by analysing whether system frequency and voltage can be operated within defined limits following various contingency events.

In relation to frequency control, two important elements in the capability mix are **system inertia** and **system spinning reserve.** These vary according to the characteristics and loading of generators which are in service at a particular time. **System Inertia** is a measure of the rotational momentum of the system and influences how rapidly frequency will change for a particular supply/demand imbalance. S**pinning reserve** is a measure of the extent to which generating units that are in service, but not operating at full capacity, are able to respond to changes in instantaneous demand**.** In more recent times, the traditional concept of **spinning reserve** has been replaced by **regulation capability** which accounts for the ability of a generator to either increase, or decrease, its output in response to load demand changes.

The **inertia** of an electricity supply system is a measure of the momentum or stored energy contained within the elements of the system that are in service at any one time. A system that contains a large number of heavy rotating elements in service, either generators or driven devices such as electric motors, will have a high inertia. The inertia of an individual piece of rotating equipment is influenced by its mass, its shape and speed at which it rotates. Large mass results in high inertia, a device that has a large diameter has greater inertia than a small diameter shaft of the same mass, a device that has a high rotational speed has higher inertia than one operating at low speed. A system with high inertia is inherently more difficult to slow down or speed up than a system with low inertia. Thus a system with high inertia will be able to withstand an imbalance trying to slow it, such as an increase in demand, for a longer period than a system with low inertia.

To quantify **regulation capability,** it is necessary to consider, for each generating unit in turn, the extent to which the generating unit can increase or decrease its load and sustain the change for a defined period. The rate at which the generator can change its load when called upon to do so is also important. Some generators are limited in how quickly they can change their output due to fuel supply limitations (the need to burn more coal for instance) or thermal restrictions (a need to manage how quickly equipment warms up or cools). The combined ability of each of the generators in service to meet increases (or reductions) in demand within given time parameters is the overall system **regulation capability**.

In addition to balancing the supply and demand of an electricity supply system under normal operating conditions, a secure system must also be able to withstand unexpected failures without compromising the supply to consumers or allowing the frequency or voltage to vary outside of designated standards. The **National Electricity Rules (NER)** state that a system must be able to withstand a **credible contingency event** which is defined as the failure of a single generating unit or the failure of a single element of the transmission system (such as a transmission circuit, transformer, or item of switching equipment). There is a requirement therefore that adequate frequency and voltage control capability is always available to manage such contingencies.

With the advent of the National Electricity Market (NEM), the management of **regulation capability** along with a number of other services required for the management of power system security were collectively grouped as **ancillary services.** Further details on the arrangements for the supply of ancillary services are provided in Chapter 4.

In addition to maintaining system security following credible contingencies, power systems are also designed to withstand a range of non credible contingencies. Non credible contingencies are situations where the power system is faced with more than one failure at a time, such as the simultaneous failure of several transmission circuits, the tripping of multiple generators, or the disconnection of very large loads not normally classified as credible. To cater for such eventualities, and thus prevent total failure of the system, **under frequency load shedding** (UFLS) schemes and **over frequency generator shedding (OFGS)** schemes are installed to automatically and progressively trip consumer load or excess generation. Trip settings for participating plant are specified at predetermined frequency levels in order to maintain frequency within emergency operating limits.

4. Characteristics of the Tasmania Electricity Supply System

4.1. General Description

Electricity generation facilities in Tasmania include 27 hydro power stations, a combined cycle gas turbine (CCGT) plant, four open cycle gas turbines (OCGT), and two wind farms. A number of small embedded generators exist also within the distribution network, e.g.: the Meander Dam mini-hydro development. A number of large industrial customers have embedded generation capability which may be in the form of heat recovery units or co-generation steam plants. Such units typically only offset load demand and do not supply power back to the network. The combined generating capacity of the network connected generation facilities is approximately 2800 MW compared with a peak load demand of approximately 1870 MW (which includes network losses).

Electricity from the major hydro and gas turbine generators is delivered by a transmission network operated by Transend Networks. Transend's asset base consists of some 3650 km of transmission lines, 9 switching stations and 47 substations. Transend provides direct connection to a small number of major industrial customers and to the distribution network operated by Aurora Energy.

The transmission network consists of a 220 kV backbone which runs from George Town substation in the north to Chapel Street and Lindisfarne substations in the south. Transmission lines also run west from George Town to connect Sheffield, Burnie and Farrell substations. The 220 kV network is supported by a number of parallel 110 kV circuits with additional 110 kV circuits supplying radial distribution substations like Avoca, Triabunna and other remote rural areas. A schematic showing the extent of the transmission network which is operated by Transend Networks is provided as Appendix 1.

At the substations, electricity is transformed to a range of lower voltages (44, 33, 22, 11 and 6.6 kV) to directly supply larger consumers and the Aurora distribution network. In other jurisdictions, it is not common for the transmission network to supply at less than 66 kV however the Aurora system does not have an extensive sub transmission network compared with larger distribution networks on the mainland.

The Tasmanian transmission network is connected to the interconnected mainland electricity grid via **Basslink**. Basslink is a ±400 kV HVDC link which runs from George Town to Loy Yang in Victoria. The interconnection consists of 290 km of undersea cable (which is the second longest operational HVDC cable in the world today) as well as approximately 68 km of overhead transmission line, most of which is located on the Victorian side. Basslink became fully operational on the 28th April 2006.

Basslink is nominally rated at 500 MW but is capable of exporting up to 630 MW of power from Tasmania to Victoria for limited time periods (up to ten hours approximately). The flow of power from Victoria to Tasmania is limited to 500 MW as measured at Loy Yang, resulting in approximately 480 MW being delivered into the Tasmanian transmission network (the balance being consumed as losses, predominantly within the cable).

The magnitude and direction of power flow on Basslink is determined by AEMO as an outcome from the National Electricity Market dispatching processes. In general, power will flow from a low spot market price towards a high spot market price on the basis that low cost generators will be dispatched first. Therefore, if the spot market price in Tasmania is lower than Victoria, Basslink will generally move toward northward flow conditions, whereas if lower priced power is available in Victoria, power flow on Basslink will move toward southward flow. The flow on Basslink is a market outcome and is not directly set by any one party.

A restriction on Basslink is that it is not able to operate below 50 MW when either importing or exporting. This ±50 MW deadband is called the “no-go zone” and requires special management when the direction of Basslink flow needs to be swapped over. The technical reasons for the no-go zone are complex and not within the scope of this paper, however it is important to appreciate that to reverse Basslink flow, it is necessary to pass through the no-go zone. To do this, power flow is actually stopped for a short period of time (in the order of several minutes) before recommencing in the opposite direction. To “stop” and “start” Basslink, the Tasmanian and Victorian power systems are each exposed to a 50 MW step which has more impact in Tasmania because of our relatively small network.

The controls which manage the operation of Basslink offer a variety of additional functions which help support the connecting networks. In the Tasmanian context, Basslink is able to offer both frequency and voltage support when not constrained by physical equipment limitations (which are most prevalent at maximum transfer and either side of the no-go zone). The ability of Basslink to transfer FCAS between the Victorian and Tasmanian regions was a key design consideration given the interconnectivity of the energy and FCAS markets within the NEM. It is important to note that Basslink only transfers FCAS from mainland service providers and is not a source of FCAS itself.

While such functionality exists, availability is limited to time periods when Basslink is in operation and not transferring through the no-go zone. Whenever Basslink is out of service, or in the process of being reversed, Tasmania must be self reliant in terms of voltage and frequency control capability. Reversal periods, albeit short in duration, can occur several times a day and require special considerations to ensure that system security is appropriately managed.

While more than adequate generating capacity is available “on island” to meet the Tasmanian peak demand, the hydro generating portfolio is limited by water availability. The energy required to meet the total Tasmanian electricity requirement is around 10700 MWh. To allow for system losses, this requires some 11600 MWh to be generated, or imported over Basslink. The total median energy inflow to the Tasmanian hydro schemes is about 8700 MWh, requiring a net Basslink import or support from thermal generation to met on island energy requirements. Some of the key aspects of managing the various hydro schemes such that maximum energy production is achieved and generating capacity is available when required are discussed in the next section of this paper.

4.2. Hydro Generation and Water Management

Hydro Tasmania’s principal hydro generations schemes are defined within 6 main catchment areas. They are the Gordon - Pedder, Great Lake - South Esk, Derwent, King - Yolande, Pieman and Mersey – Forth schemes, geographical and technical details of which are available on Hydro Tasmania’s web site.

Each scheme is unique and designed to best utilise the water inflow and topography of the particular catchment area. The schemes may be characterised in terms of the water stored within the catchments.

- The Gordon - Pedder and Great Lake – South Esk schemes have **large storage** capacities which would take some years to fill from low levels even if generation was constrained.
- The King – Yolande, Pieman, and Mersey - Forth schemes have **limited storage** relative to their capacity to generate and these storages can fill from near empty to full in a short period (several weeks to several months) of sustained heavy rainfall.
- The Derwent scheme which falls between the large and limited storage categories and is therefore termed an **intermediate storage** scheme.

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 but regular operation at or below this level is considered unsustainable.

While total system storage is important water storage in each scheme must be maintained in order for the generating capacity associated with that scheme to be available. However if the inflow to a particular catchment is greater than the rate at which water can be utilised by the generating plant the catchment level will rise and may fill to the point where water is spilt and therefore not available for the generation of electricity. Spill is more likely to occur where limited storage is available for particular generating units and is therefore usually associated with limited storage systems.

By way of example Lake Mackenzie which is at the head of the Mersey - Forth scheme has a total storage capacity, of 45 GWh (for convenience dam capacity is measured in units of energy which may be generated with that water rather than volumetric units) compared with the Great Lake which has a capacity of 6567 GWh. Water from the Lake Mackenzie flows through the Fisher Power Station and thence through Lemothyne, Cethana, Devils Gate and Paloona Power Stations to the sea. Recently recorded heavy rain events have shown Lake Mackenzie storages increasing at a rate of nearly 25 % of full capacity in a week during a period when Fisher Power Station was operated at maximum capacity. Had the lake been over 75% full at the outset of the heavy rain event spill would have occurred.

In order to manage the limited storage schemes in a way that minimises the chance of spill storage levels are reduced ahead of expected heavy rain periods in winter and only allowed to rise ahead of expected drier periods in summer months.

It is also possible that water spilt from the head of a hydro scheme may inundate downstream power station **pondage** and cause spillage from these facilities as well. The smaller dams built to establish the head necessary for hydro plant and provide some buffer storage for operational purposes are sometimes referred to as ponds. Spill from such downstream power stations may also occur or be exacerbated by inflows from other sources other than the primary source.

The strategy to minimise spill means that the generation from limited storage schemes tend to be maximised during high inflow periods (nominally winter months) and revert to back up and/or peak load duty during periods of low inflows.

4.3. Operational Responsibilities of AEMO and Transend

Responsibility for the day to day physical operation of the power system that makes up the National Electricity Market (NEM) is managed by the Australian Energy Market Operator (AEMO). AEMO is also responsible for managing the commercial aspects of the electricity market but these arrangements will not be considered in detail in this paper except where it is necessary to differentiate between the arrangements for the supply of energy and ancillary services, or to explain the background to certain technical issues.

AEMO's responsibility covers the dispatch of generating plant and the operation of the transmission system. The physical operation of distribution networks is the responsibility of the relevant Distribution Network Service Provider (DNSP) which in the case of Tasmania is Aurora Energy.

AEMO's primary operational task is to manage power system security which includes ensuring that adequate generating facilities are in service to meet the cumulative electricity demand of all consumers at all times. To do this, AEMO estimates the electricity demand in each region (including Tasmania) for each half hour period of the day on the day before the demand has to be met. AEMO then schedules generating plant whose operators have advised that they available, such that the demand can be met and all system security criteria are satisfied. The schedule is primarily selected of the basis of offers from generators but importantly, it must be practical from a technical point of view. In scheduling generating plant, AEMO takes into account generation plant start up times, allowable rates at which individual generators can be loaded / unloaded and other relevant operating constraints that may apply.

As an important adjunct to the scheduling of generating plant, AEMO must take into account the ability of the transmission system to transmit the electrical energy from generators to end users without breaching any system security criteria. Consideration needs to be given to the capability of the system for both normal operating conditions as well as following any credible contingency events. To enable AEMO to do this every five minutes (generators receive new dispatch targets on a five minute cycle), the **technical envelope** of the power system is described in what are termed **constraint equations**. Constraint equations are embedded within the National Electricity Market Dispatch Engine (NEMDE) as mathematical equations. NEMDE is a computer based control system employed by AEMO to determine which generators should be dispatched in the market based on submitted price offers, the electrical demand that needs to be served, and the physical limitations of the power system.

It is interesting to note that approximately 25 percent of the constraint equations developed by AEMO are related specifically to the Tasmanian system due to its unique technical characteristics.

AEMO is also responsible for ensuring that measures necessary to maintain system security are provided for and maintained at adequate levels. Some measures are embodied in operational rules but more important are those that control key technical characteristics through the acquisition of ancillary services. Ancillary services are grouped under one of the following three categories;

- Frequency Control Ancillary services (FCAS)
- Network Control Ancillary services (NCAS)
- System Restart Ancillary Services (SRAS)

FCAS can be further divided into two general categories. The first are services that are required for the normal regulation of frequency in response to small deviations in load demand that continuously occur over time. These are referred to as **Regulation FCAS** and provide the necessary regulation capability as discussed previously. The second category consists of services that are required to control system frequency following credible contingency events such as the loss of a generating unit or major load.

These are referred to as **Contingency FCAS**. Generators are selected for the supply of both forms of FCAS via a market arrangement managed by AEMO. The commercial arrangements of this market are not detailed in this paper. It is however necessary to appreciate that there is a relationship between the dispatch of FCAS and the dispatch of energy. In practice, the energy and FCAS markets operate in parallel such that price and availability of each can affect the resulting generation dispatch outcome.

Regulation FCAS is provided by selected generators responding to control signals sent by AEMO through the **Automatic Generation Control (AGC)** system. AEMO utilises measurements of system frequency as well as other variables (such as accumulated time error) to decide whether to increase or decrease the output of selected generating units. Control signals are sent approximately every four seconds so as to maintain system frequency within its normal operating band.

Contingency FCAS services are divided into six specific categories being, Fast Raise (6 second), Fast Lower (6 second), Slow Raise (60 second), Slow Lower (60 second), Delayed Raise (5 minute), and Delayed Lower (5 minute). Raise service are used to correct for under frequency events (below 50 cps), while lower services are used to correct over frequency events (above 50 cps)

In general terms, the fast raise and lower services are provided to arrest the immediate frequency deviation that occurs following a contingency event. The slow raise and lower services enable frequency to be progressively restored back toward its rated value of 50 cps. The delayed services enable operation of the network to be maintained at 50 cps until changes in the generation dispatch profile can occur to compensate for the contingency event that caused the initial frequency deviation. While most contingency services are provided by generating plant via their governor control systems, it is possible for load customers to participate in the FCAS raise markets. If they so choose, raise FCAS can be provided by reducing load demand in response to under frequency conditions.

Detailed information on the Tasmanian Frequency Operating Standards is provided in Chapter 6.

AEMO determines the amount of contingency FCAS required for each of the six services on a continuous basis. The level of each service is dependent on system load demand and the size of the largest contingency that needs to be managed. For the Tasmanian region, system inertia is also considered. The failure of the largest generator on the system (which was up to 144 MW prior to the commissioning of Tamar Valley Power Station for which special provisions were made as detailed in Chapter 7) is one determinant of the level of raise FCAS services required. Similarly, disconnection of the largest individual load on the system is one determinant of the level of lower FCAS services required. The other determinant is the power transfer occurring across Basslink and consideration of what control action would be initiated by the Frequency Control System Protection Scheme (FCSPS) in response to a Basslink trip. Further discussion on this issue is provided in Chapter 5.

AEMO schedules FCAS services for each of the categories from generating plant whose operators have advised that they available to provide some or all of the services. As the amount of raise and lower services available from an individual generator is determined by its power output relative to its upper and lower operating limits, it is necessary for AEMO to balance the real time requirements for energy and FCAS in order to ensure sufficient FCAS is available.
This process is called **co-optimisation** and is based on achieving minimum cost of supplying both energy and FCAS concurrently. The co-optimisation process occurs within NEMDE every 5-minutes in order that new dispatch targets can be issued to generators.

Network Control Ancillary Services (NCAS) are also subdivided into two distinct services; Voltage Control and Network Loading Control. Voltage Control Ancillary Services are necessary to control the voltage on the network to within specified tolerances and can be provided either by operating generating units or static compensating devices. Network loading ancillary services are used primarily to ensure that regional interconnectors are operated within their technical capabilities. The special arrangements applicable to the operation of Basslink, Tasmania's only interconnector with mainland Australia, means that this ancillary service category is not required in Tasmania.

System Restart Ancillary Services (SRAS) are required so that the power system, or significant portions of it, can be restarted following a complete or partial failure (often referred to as "system black" conditions). To be eligible to provide this service, a generator must be able to start and supply energy to the transmission system without any external source of power supply to begin with. This generally requires some special design provisions within the power station, as well as its control systems, meaning that not every power station is capable of providing black start services.

In carrying out its tasks, AEMO is dependent on a wide range of information being provided on the state of all elements within the power system. This information is supplied to AEMO via communications systems which rely on a number of different technologies. It also has to have appropriate communication with personnel directly responsible for the operation of various system elements. Information is sourced directly in some cases but is usually channelled via control centres operated by the principal system participants including generators and TNSPs (such as Transend). In some cases AEMO is able to directly control elements of the power system from one of two mainland control centres located in New South Wales and Queensland.

In the event of a failure of any of these communication networks, and particularly if the failure results in the Tasmanian system being isolated from the mainland, there is need for on-island system control facility. It is therefore necessary for Transend to maintain the ability to provide various system control capabilities including generation dispatch functions such as AGC.

5. Technical Impact of Basslink

5.1. System Security Issues and the System Protection Scheme

The interconnection of the Tasmanian and mainland electricity networks via Basslink has provided, for the first time, an opportunity for Tasmanian participants to trade in the NEM. Basslink has however required that special provisions be made to enable the link to be operated up to its design capability while at the same time ensuring that system security is not compromised. This is especially true for the Tasmanian region given its relatively small size. Separate provisions are necessary to manage Basslink for both northward and southward flow conditions.

As previously explained, AEMO procures FCAS raise services necessary to cover the failure of the largest generating unit on the system. When energy flow is southward into Tasmania, Basslink effectively appears as generator with up to 480 MW of capability. As Basslink has no duplication, loss of the link is classified as a credible contingency event. At the time of Basslink commissioning, this was significantly above the next largest generator contingency (being 144 MW) and would have required unrealistic volumes of raise FCAS to be available in Tasmania to manage the resulting frequency excursion if Basslink were to trip.

Conversely, during export conditions, Basslink appears as a load of up to 630 MW to the Tasmanian network. The next largest contingency typically setting lower FCAS requirements was approximately 210 MW. As for southward flow conditions, the procurement of the additional FCAS was considered to be a non-viable solution to manage unexpected loss of Basslink and the resulting frequency excursion that would follow.

The solution for both situations was the development of the **Frequency Control System Protection Scheme (FCSPS)**. The FCSPS is an automated control scheme that rapidly disconnects either excess generation or contracted load immediately following the unexpected loss of Basslink power transfer. In the case of Basslink northward flow conditions, excess hydro generators are disconnected to assist with the control of the resulting over frequency event. For Basslink flows southward, the solution was to contract with major electricity consumers (predominantly major industrial customers) to trip non-sensitive load to control the resulting under frequency event. The tripping of generation or load can occur within several hundred milliseconds (several tenths of a second) of Basslink power transfer being interrupted. The speed of the control actions is critical if system frequency is to be adequately managed within prescribed limits.

The magnitude of load or generation that is "armed" by the FCSPS varies according to Basslink power transfer levels. If insufficient load or generation is made available to the FCSPS, Basslink power transfer will be constrained to within the capability of the Tasmanian network to control the frequency excursion that would result from loss of Basslink. While the availability of generation to the FCSPS is generally not an issue for northward flow conditions (as this can be managed directly by Hydro Tasmania), the availability of load for southward flow conditions is more variable and subject to individual commercial arrangements with each participating customer.

While much of the hardware and software necessary for operation of the FCSPS is owned and maintained by Transend Networks, Hydro Tasmania is ultimately responsible for the provision of generation and contracted load blocks to the FCSPS (through its own commercial negotiation processes). As previously stated, if insufficient resources are made available to the FCSPS, Basslink power transfer is constrained appropriately so that power system security is not compromised.

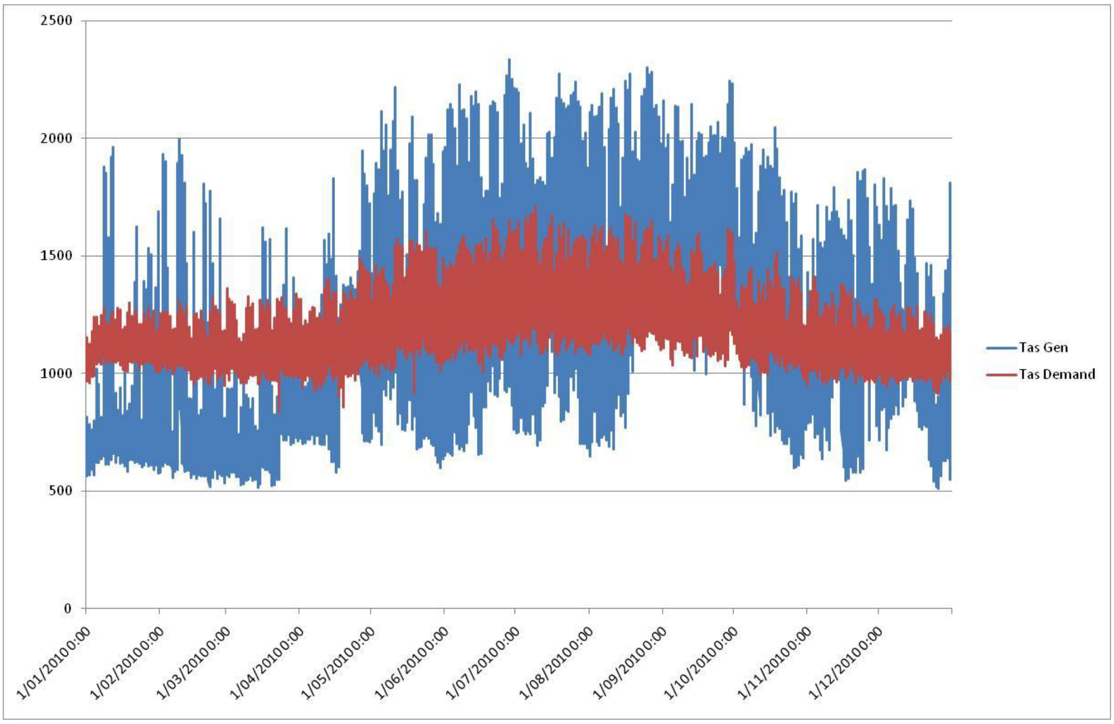
One other System Protection Scheme exists that was designed and implemented for the purposes of maximising Basslink transfer capability. The **Network Control System Protection Scheme (NCSPS)** is only in service during periods of Basslink northward flow and allows specific circuits in the Tasmanian transmission network to be operated above their normal capacity limits. If a transmission circuit unexpectedly trips, resulting in other circuits becoming severely overloaded, the NCSPS automatically and rapidly reduces the output of nominated hydro generators such that the overload conditions are promptly removed (in some cases, within 10 seconds). The NCSPS was designed and implemented to maximise the export capability of Basslink without needing to significantly augment the Tasmanian transmission network, thus saving on the infrastructure costs.

5.2. Impact of increased utilisation of installed generation capacity

Prior to the commissioning of Basslink, it was necessary to schedule on-island generation to meet the total Tasmanian electricity demand. With Basslink in operation, Tasmanian demand may be met from a combination of on island generation plus transfer over Basslink. For Basslink to flow northward, it is necessary to schedule generating plant to meet both the Tasmanian demand plus the level of power required to be transmitted to Victoria.

Figure 5.1 shows a plot of half hourly Tasmanian MW demand in red superimposed over a plot of on island MW generation in blue for the whole of 2010. Areas of blue below the red trace indicate periods of Basslink southward flow where on island generation was less than that required to service the total Tasmanian load demand. Areas of blue above the red Tasmanian demand trace designate periods of northward flow when on island generation is meeting both Tasmanian load demand as well as transfer requirements. Note that maximum northward flow is approximately 630 MW and that total on island generation has on occasions exceeded 2300 MW. Maximum southward flow is approximately 480 MW resulting in periods of time where little over 500 MW of on island generation was required to service Tasmanian demand.

Figure 3 - Tasmanian Demand and Generation Profile for 2010



Source: Transend Networks

6. Other impacts of NEM interconnection

Prior to Tasmania joining the NEM, there were a number of differences in the standards and operating methodologies applicable to the mainland and Tasmanian electricity systems. One of the key differences was, and still is, the applicable frequency operating standards. The history behind the need for a separate **Tasmanian Frequency Operating Standard** (TFOS) lies in the fact that Tasmania was, and still is, dominated by hydro generating units. The physical characteristics of this type of generating plant are such that they are not good providers of what is now referred to as Fast FCAS. Control of frequency within very narrow tolerances is difficult due to the slower response characteristics of hydro plant to frequency excursions. The small size of the Tasmanian power system is also a contributing factor. As hydro generating units are robust and able to tolerate relatively wide frequency excursions without risk to their mechanical integrity, the situation was historically a non-issue.

In comparison, mainland states are dominated by thermal generators which are typically very good at providing fast FCAS but intolerant to frequency excursions away from 50 cps for any significant periods of time. Coupling this with the fact that the mainland power system is very large and now fully interconnected across the eastern seaboard states, allows for much tighter tolerances to be successfully applied with supporting justifications.

On joining the NEM in May 2005 the Tasmanian jurisdiction was provided with a derogation (or exemption from compliance with the NEM standard existing at the time in relation to frequency standards) on the basis that it would be reviewed by the **Reliability Panel (RP)** of the **Australian Energy Market Commission (AEMC)** within 12 months. The RP in its 2006 review considered that experience with Basslink was required in order that a meaningful re-assessment of the Tasmanian situation could be conducted. The eventual review of the Tasmanian Frequency Operating Standard was conducted by the RP during 2008 and a final report issued on the 18 December 2008 which included a revised standard for the Tasmanian region.

In its review, the RP acknowledged the following key issues:

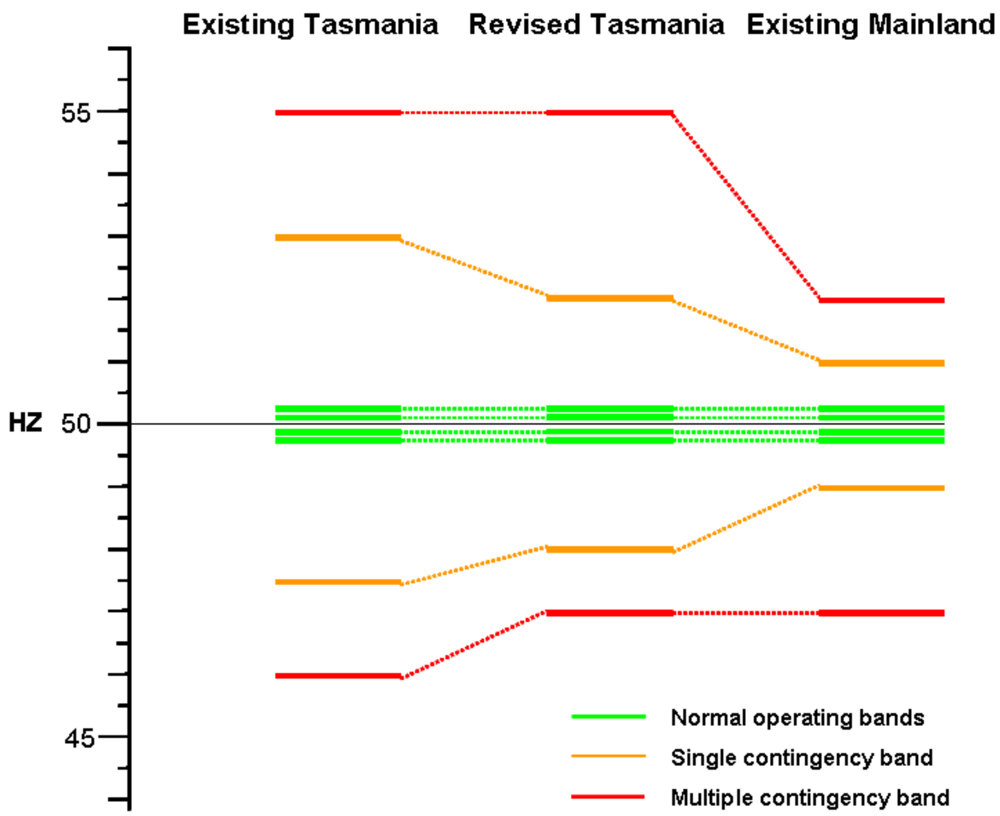
- That many thermal generating units are required to trip at 47 cps and can only operate below 48 cps for limited periods of time due to inherent design constraints. Similar restrictions on over frequency capability were also noted.
- It noted that the Tasmanian system has relatively large load, generator and network contingencies, as a proportion of the total system size.
- That the Tasmanian system can operate with relatively low inertia, particularly when Basslink is flowing south coincident with times of low Tasmanian load demand.
- That the Tasmanian region can experience shortages of fast acting frequency control ancillary services (FCAS).

In its final report, the RP recommended tightening the frequency limits (as detailed in Figure 4) but not adopting an equivalent NEM standard for the Tasmanian region. This was largely on the basis of practicality, recognising that the dynamics of the Tasmanian power system do not lend themselves to achieving such outcomes without unjustifiable burden on market participants.

The RP also revised target times for frequency restoration following excursions into each of the respective bands. The new target restoration times are less demanding than those required of the mainland system.

In order to limit the additional FCAS requirements required as a result of the tightened frequency standards, the RP determination included a requirement that the largest generator contingency be limited to 144 MW. Generators having a capacity in excess of this are required to install protection schemes similar in principal to that of the Basslink FCSPS where the effective contingency size is made equivalent to 144 MW by the rapid disconnection of load (procured by the generator for the specific purpose). This was a significant new requirement and a notable outcome from the 2008 review.

Figure 4 - Existing and Modified Frequency Standards



Source: AEMC, RNPP report, 18 December 2008

The full report produced by the RP is available from the AEMC website referenced below and includes submissions made by all parties who participated in the formal consultation process leading up to the final determination.

http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Frequency-Operating-Standards-for-Tasmania.html

7. Technical Impact of Tamar Valley Power Station

Tasmania's only operational large scale thermal generation is located at Tamar Valley Power Station at George Town in the north of the state. The station comprises of a 209 MW combined cycle gas turbine (CCGT) and four smaller open cycle gas turbines (OCGT) totalling 178 MW. The CCGT consists of a nominal 141 MW industrial gas turbine, a heat recovery steam generator and an associated 68 MW steam turbine, all supplied by Mitsubishi. The gas and steam turbines drive separate generators. The power station also has three 40 MW Pratt and Witney OCGT's which were originally purchased and installed by Hydro Tasmania prior to sale of the site. In recent times (2009), an additional 58 MW Trent Rolls Royce open cycle gas turbine has been added. Note that the rating of the gas turbines is nominal and the actual available output of each is dependent on ambient temperature, humidity and the physical condition of component parts.

The CCGT unit has a high energy conversion efficiency compared with other thermal plant and is designed to be operated continuously or cycled on a daily or other basis, to meet system requirements. The open cycle gas turbines may also be operated continuously but because their energy conversion efficiency is relatively low, their primary role is to cover other plant outages, provide fast start capability to exploit periods of very high spot market prices, and provide peak load generation during periods of significant energy demand (which generally correlate with higher than average spot market prices as well). Note that while gas turbine plant may be cycled from on to off frequently such operation results in a need for more frequent routine inspections and maintenance.

As noted in Chapter 6, the RNPP in its December 2008 report recommended that the largest generator contingency be fixed at 144 MW and that generators having capacity in excess of this, be required to put in place arrangements similar to the Basslink FCSPS. Consequently it has been necessary for the owners of TVPS to contract with major electricity consumers to disconnect load in the event of a TVPS trip. A minimum of approximately 70 MW of load is required to be procured under contract to allow TVPS to operate at full rated output. The technical management of the scheme is carried out by Transend on a contracted services basis, similar in nature to the arrangements for the Basslink FCSPS.

Although the Tamar Valley CCGT plant may be cycled to meet load requirements, the unit is currently run continuously to match gas supply arrangements that have been contracted for the power station. This mode of operation has two important impacts on the overall electricity supply situation in Tasmania. The first relates to the total energy requirements of the state. Subject to median water inflows being received, the electrical energy capability of the hydro schemes is in excess of that required to make up the state's total energy requirements and provides for a net export situation. The second impact is that it provides greater flexibility in maximising export opportunities, even during periods of high on island demand.

8. Technical Impact of Large Scale Wind or Solar generation systems

Tasmania is considered to have a large number of high quality wind farm sites based on the excellent wind regimes that exist across much of Tasmania's land area. However the remoteness of many of the sites, coupled with the relatively small size of the Tasmanian power system, poses a number of technical challenges for their development.

While wind turbines can physically offer reasonable inertia (predominantly in the rotating hub and blades), the existing methods of interfacing the plant to the electrical power system results in little or no inertia being offered to the network. The use of power electronic interfaces and/or induction generators results in a "decoupling effect" whereby the speed of the wind turbine is no longer fixed to the frequency of the power system. When a large number of wind turbines are in service, the combined effect is to reduce the overall system inertia and increase the requirements for FCAS. Conceivably, with further wind farm development, it may be necessary to have other generating units in service but operating at minimum or inefficient outputs, just to increase system inertia and/or provide the necessary FCAS to satisfy power system security requirements. Alternatively, special purpose plant or modifications to existing plant may be required to meet the requirements in a practical manner. This impact would become particularly important during low load situations which are usually experienced at night.

Although a number of wind farm sites have been identified in central and north east Tasmania, the majority are located in the north west and west of the state, in areas where the transmission system has limited capacity to handle additional generation infeed. Any major new wind farm would therefore require significant transmission system development if all generation in the area was to be able to operate unconstrained. A similar situation would arise if east coast developments in addition to Musselroe were to occur.

Due to the generation technology employed within wind turbines, their reactive power control capability is highly variable over their MW operating range. Coupled with this, the technology of wind turbines also makes them less robust in their response to network fault conditions. As a result, **fault ride through (FRT)** is a significant design consideration. FRT is essentially the ability of a wind turbine to remain in-service during and immediately after a disturbance in the power system. The National Electricity Rules (NER) requires that all generators remain in service for at least credible contingency events so as to avoid cascading failure of the entire network. To mitigate both their inherent reactive power capability and/or FRT issues, wind farms are often supported by auxiliary plant in the form of capacitors, static var compensators, synchronous condensers or a combination of such reactive compensation devices. This increases the initial capital outlay but is necessary for the purposes of managing power system security. The electrical characteristics of the network connection point (which is turn is driven by the physical location of the wind farm) has a significant bearing on the reactive support requirements and hence the capital expenditure that is necessary.

The variability of wind as a fuel source means that wind turbine plant cannot always be relied upon to meet system load requirements. While there is an excess of traditional synchronous generating capacity in Tasmania, a certain level of intermittent generating plant can be accommodated, with the inherent fluctuations of wind managed by other online generating units. This issue will need to be carefully managed in the future if wind penetration levels continue to increase. As the dispatch of traditional synchronous generating plant becomes more “sparse” (i.e.: a lesser number of hydro and thermal units online at any given time), consideration needs to be given as to how short and long term fluctuations in wind generation output will be managed so that the security and reliability of energy supply to customers is not compromised.

Significant levels of solar PV present similar challenges as well given that they are also intermittent generators of electricity relying on a variable fuel source. As solar PV systems have generally been connected into the distribution system (in the form of domestic or small scale commercial installations), it is often claimed that they are an ideal distributed generation technology and their widespread use could reduce the capacity requirements of conventional distribution systems. However in Tasmania, peak demand tends to occur in winter evenings when solar PV systems are not able to generate. Given that few people install expensive energy storage facilities in unison with PV (such as batteries), the distribution systems are still required to be sized to meet full peak load requirements. It is therefore somewhat of a fallacy to assume that embedded generation having an intermittent characteristic reduces the requirements for distribution network development.