EVALUATION OF OPTIONS FOR AN ANCILLARY SERVICES MARKET FOR THE AUSTRALIAN ELECTRICITY INDUSTRY

A Project Commissioned by the NEMMCO Ancillary Services Reference Group

FINAL REPORT

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GLOSSARY OF TERMS

AC Loadflow Model: A mathematical model of an electrical network that includes an explicit representation of voltage, angles and real and reactive power, and potentially other facilities such as explicit models of contingency constraints. Such a model could be embedded in a nodal energy market model.

AGC regulation: A sub-task of AGC explicitly concerned with the management of frequency and time errors.*Ancillary Service (AS):* A set of technical services necessary or desirable to support the secure trading of electricity over the network.

Area Control Error (ACE): An estimate of the MW generation deficiency in a given control area. In the NEM, a control area is usually the whole of an interconnected system.

Automatic Generation Control (AGC): A centralised process whereby generators are controlled to meet generation targets set by the energy market and by the requirements to manage frequency and other deviations.

Contingency control: In the context of an electricity system, the management of possible event whose timing is unpredictable but which can potentially disturb the system, thereby requiring explicitly measures to be taken beforehand to protect system security.

Continuous control: In the context of an electricity system, the management of a particular technical variable such as voltage or frequency on an ongoing basis.

Cost Reflective Network Pricing (CRNP): The methodology used in the NEM to allocate location-specific costs of the transmission network to loads.

Dispatch Price: An energy price (regionally-based) calculated by the SPD process just prior to the start of the 5-minute dispatch period to which it applies.

Distribution Network Service Providers (DNSPs): Code participants who provide the network that connects end users to a point of connection to the transmission network.

Enablement: A process by which a facility is made ready to provide an ancillary service should a contingency occur. In some cases enablement is used to provide a continuous service when there is no current means to measure continuous performance.

Energy Deviations: The difference between actual energy production or consumption and that which had been scheduled through the energy market SPD process.

Energy Deviations Market: An arrangement whereby energy deviations are paid and charged to parties in the energy market according to an accounting process based on a real time pricing formula. This formula is designed to reward behaviour that tends to correct frequency deviations, and charge for behaviour that causes them.

Filtered System Error (FSE): A system-wide variable derived from the System Error by a calculation that smooths out very short-term (of the order of seconds) fluctuations.

Frequency Control Ancillary Services (FCAS): A group of technical services that are provided to manage frequency and time errors in the system to within standards set by the NECA Reliability Panel.

Half-hour Energy Market Price: In the context of the NEM, this is a regionally-based price calculated as the arithmetic average of the 5-minute dispatch prices determined by the SPD process within the half hour.

Light on the Hill: A term used in this report to describe the future time and ultimate vision of how the AS markets should operate.

National Electricity Market (NEM): The electricity market that operates in Australia under the National Electricity Code.

National Electricity Code (Code): The formal rules for the operation of the NEM.

National Electricity Code Administrator (NECA): The organisation set up under the National Electricity Law to administer the Code

National Electricity Market Management Code (NEMMCO): The organisation set up under the National Electricity Law to run the NEM and to operate the electricity system.

NECA Reliability Panel: A Panel set up under NECA to make determinations relating to reliability standards in the NEM.

Network Control Ancillary Services (NCAS): A group of technical services that are provided to support and enhance the secure power transfer capability of the network.

Network Service Providers (NSPs): Code participants who provide network transfer capability to the NEM.

One-way Market: A term used in this report to describe a market arrangement where a single buyer (usually NEMMCO) procures services through some competitive process. A key characteristic of a one-way market is that the requirement for the service is determined by the buyer, and not by any direct beneficiaries of the service, so that some means must be found to pay for the services procured.

Real Time Pricing (RTP): The pricing mechanism proposed for the *energy deviations market*, whereby prices are calculated at very short time intervals (of the order of seconds) depending on the physical state of the system at the time.

Spot Market: A market that operates in the timeframe of the energy market established by the NEM: i.e. prices are determined each 5 minutes and settled on the half-hour. This is to be distinguished from a real time market (using *Real Time Pricing*), which is a characteristic of the energy deviations market proposed in the Evaluation Report.

Scheduling, Pricing and Dispatch (SPD): The process by which facilities operating in the energy market are scheduled for operation, their output or consumption priced and the instructions issued (by NEMMCO) for actual operation. In the NEM this operates on a 5-minute time-step at present.

System Control and Data Acquisition (SCADA): A geographically dispersed system for gathering data throughout the electricity system, processing it centrally and transmitting signals to control electricity facilities. In the NEM this operates in tiers run by NSPs and, at the peak, NEMMCO.

System Error: A term used in this report to represent a value calculated by the AGC that includes frequency error, time error and various other adjustments, but prior to being "filtered" (see *Filtered System Error*).

System Restart Ancillary Service (SRAS): The AS that provides facilities to allow the system to be re-started in the event of a widespread system failure.

Transition: A term used in this report to describe the period of AS market evolution prior to the achievement of the light on the hill, which is the long-term vision of how AS markets should operate.

Transmission Network Service Providers (TNSPs): Code participants who provide high voltage network transfer capability to the NEM. These are currently regionally-based.

Two-way Market: A term used in this report to highlight a market arrangement whereby the beneficiaries of particular AS trade directly with potential AS providers through some mechanism managed by NEMMCO. NEMMCO does not directly determine how much is traded, but manages the system to maintain system security depending on the outcome of that trading.

EXECUTIVE SUMMARY

In its final determination on the Code, the ACCC required that NEMMCO review the arrangements for providing ancillary services in the National Electricity Market (NEM). This review should consider the possibility of developing market-based arrangements in ancillary services, including a short-term market. The review has two phases:

- Phase 1 will review the framework established by the ASRG, and then evaluate the different ancillary services and advise appropriate arrangements;
- Phase 2 will address the mechanism for "who pays and how much" for the services.

A Framework report for Phase 1 dated December 1998 is available on the NEMMCO Web site (1). The current report deals with the evaluation component of Phase 1. As the question of "who pays and how much" is the subject of a second brief, the report endeavours to be neutral on that issue. However, it has not been possible to avoid the issue altogether.

What are Ancillary Services?

The Framework defines ancillary services as those services that provide for the power system security, quality of supply and enhanced spot market trading benefits that would not be voluntarily provided by Market Participants on the basis of energy prices alone. They are required to ensure that discrepancies between the commercial model in the NEM and the underlying physical behaviour of the electricity industry are dealt with. The Framework then goes on to define and describe the characteristics of eight specific services. For the purposes of analysis in this report, these have been assembled into three broad groups as set out below.

- Ancillary services concerned with balancing power supply and demand over short time intervals throughout the system; the ***Frequency Control Ancillary Services (FCAS);***
    - Frequency management – small deviations (including time error management)
    - Frequency management – large deviations
- Ancillary services concerned with maintaining and extending the operational efficiency and capability of the network within secure operating limits; the ***Network Control Ancillary Services (NCAS);***
    - Voltage control – continuous
    - Voltage control - contingency
    - Stability control
    - Network loading contingency control
    - Spot market trading benefits

- The Ancillary Service concerned with recovery from a partial or total power system failure; the ***System Restart Ancillary Service (SRAS);***
  - System restart

These groupings are not intended to disguise the wide variety of technical options that can be applied in many cases, some of which, such as load shedding, can be applied to many of the services defined here as well as to others not so defined, such as those that could support the operation of distribution networks. Nearly all classes of Code and Market Participants are potentially involved including transmission and distribution network service providers, generators, distributors, retailers and the market operator.

The dominant (but not the only) motivation for providing ancillary services is to manage risks associated with short-term contingencies in the system, such as generator and transmission line outages, for a given system operating pattern. If not so managed, such contingencies could cause the system to fail. The Code defines the criteria that NEMMCO are required to satisfy to maintain a secure system. These criteria require translation into operating policies and in so doing many judgements are required. Robust and transparent procedures for regulating this process will be central to any development of markets in ancillary services.

Significance of Ancillary Services

NEMMCO's estimate for the cost over 12 months under current arrangements is about $130 million, including Queensland. Early figures from the south-east Australian system based on current arrangements suggest the following approximate breakdown between the groups defined above:

- Frequency Control Ancillary Services 65%
- Network Control Ancillary Services 25%
- System Restart Ancillary Service 10%

In very broad terms, the total cost of ancillary services is likely to be around 5% of wholesale energy market turnover at current prices. The impact of this not insignificant amount is magnified by the fact that costs are currently passed by NEMMCO onto retailers and other energy spot market loads. That cost is difficult to hedge, and the resultant uncertainty has a very significant impact on retailer margins, said to be about 2-3% of turnover.

While the balance between services and their total cost might change, the current predominance of FCAS in the cost breakdown is clear. FCAS can be provided from many sources over a wide geographic area and so the scope for market arrangements sustained by high levels of competition is good. For these reasons, FCAS has been selected as most suitable for early market development. There are prospects to develop markets in NCAS as well, although not necessarily short-term markets as proposed for FCAS. However, there are more steps to be traversed before markets in NCAS could develop.

Related National Electricity Market Issues

The approach to ancillary services affects, and is affected by, other areas of the NEM that are currently subject to reviews by NECA.

Transmission & Distribution Pricing

NECA's draft report (Ref 3) canvasses and provides guidelines for entrepreneurial network inter-connectors, considers the further development of an inter-regional hedge market and canvasses nodal spot pricing and congestion contracts along the lines of that implemented in the PJM system in the US. These matters are closely related to the NCAS group in particular, to the extent that progress on the matters canvassed by NECA will affect progress in the establishment of markets in NCAS, and vice-versa.

Capacity Mechanisms and the Value of Lost Load (VoLL)

The concern about the adequacy of the remuneration to generators that will encourage adequate investment in the "top end" of the market is closely affected by the approach to the provision of FCAS, and how it is paid for in particular. This issue will be addressed further in the "who pays and how much" phase of the ancillary services project, but the relationship is noted here.

Development of the demand-side of the NEM

NECA has recognised the role of the demand-side in clearing the market at the "top end" and intends to promote its development. The demand-side, and even the same flexible demand-side facilities that NECA intends to encourage in order to help the energy market to clear, will play a closely similar role in the development of ancillary services markets. This mutual dependency should be recognised and re-enforced.

Evolution of Ancillary Service Arrangements in the NEM

The monopoly utilities that preceded the current disaggregated electricity industry arrangements had a broad brief to supply reliable electricity of adequate quality. Elements now defined as ancillary services were provided as a matter of course. There was no functional or legal separation between the production and delivery of energy (to distribution system boundaries, if not to end-users) and the provision and maintenance of a secure and reliable power system, to which ancillary services contribute. The provision of ancillary services was *internalised* within the organisation that produced and delivered energy.

Under the new dispensation the institutional arrangements relating to ancillary services are very different. The primary exchange of the tradeable good, in the form of electrical energy in the spot market, is functionally and legally separated from the provision, maintenance and regulation of a secure power system. Under this arrangement the production and consumption of energy produces *external effects*, including operational risks that require action by NEMMCO to maintain a secure power system. Such actions include the procurement and dispatch of ancillary services, the costs of which are not at present directly included in the transaction price in the energy market.

In terms of regulatory economics, the current model is that of a central public regulator (NEMMCO) procuring services to maintain system security standards, *without inquiring into the responsibility or accountability for whatever produced the need for the service*. The cost of procuring and dispatching these services is recouped by levying taxes on the purchasers of the primary traded good according to the consumption of that good. This is an unusual method for defraying the costs of regulation and of maintaining the integrity of a system. The usual model would allocate costs to those who cause the requirement so that they bear the results of their actions.

Current Ancillary Service Arrangements

At present procurement of ancillary services proceeds with the following priorities:

- utilisation of resources available to NEMMCO under the mandatory provisions of the Code and connection agreements;
- competitive tenders where there are competing providers (who, to date, with the exception of interruptible loads, have been energy suppliers in the energy market);
- negotiated contracts where the potential provider(s) of the service have market power, either generally or because of spatial considerations; and
- direction, if necessary and as a last resort.

Payment by NEMMCO to providers of ancillary services is split into *availability, enablement, use* and *compensation* components. Not all components apply in any specific case. Payment for *availability* is intended to cover ongoing fixed costs. Payment for *enablement* covers the cost of making a resource ready for use. It is sometimes a substitute for a usage payment if measurement is impractical. Payment for *use* covers additional costs that may be incurred when the resource is actually used. *Compensation* covers the assessed opportunity cost of providing the service when it might otherwise have been used profitability for energy or other production. The dispatch of FCAS facilities for enablement is, with some exceptions, achieved through facilities coded into the energy market SPD logic. However, for this and other ancillary services, all the resources used are under long term contracts, and they are enabled and used according to long-term offer prices written into those contracts.

None of the parties most involved in the current arrangements finds them satisfactory. Contract negotiations for the initial round were protracted and difficult both for NEMMCO and the parties that responded to NEMMCO's invitation to tender. Generators feel they are unfairly and unreasonably required to provide too many services for free under the mandatory requirements of the Code and connection agreements. Retailers feel they are unfairly and unreasonably required to pay for all services, when they consider that they are not the cause of the requirement (although their customers may be). Many of these real or perceived problems are inherent to the central procurement of ancillary services overlaying a competitive energy market.

Ancillary Service Improvements

Within this model some significant improvements are possible in the short term, including:

- reviewing the standards, management and public reporting applied to each ancillary service group , with a view to rationalising current expenditure levels;
- shortening the period of and widening participation in the current FCAS "enablement" market by supporting short-term bidding by all capable Market Participants and paying a common clearing price to each; and
- as part of the later "who pays and how much" stage of the review, allocating the costs of providing ancillary services to those who caused the need for those services, following the principles as outlined in the terms of reference for this review.

While these changes should reduce ancillary service costs, difficulties arising from the current functional and legal separation between the energy market and ancillary services will remain. The current separation was a compromise that allowed a clean and relatively simple energy market to be established quickly, but it is now reasonable to consider arrangements that will again *internalise* these services with the energy market i.e. by ensuring that trade in energy brings forward the necessary ancillary services without the need for direct external procurement. Such a re-integration of the energy and ancillary services regulatory logic is the essence of the light on the hill proposed by this report.

The Light on the Hill

The theory of externalities was addressed by the English economist AC Pigou in 1932. His analysis suggested the now widely known and implemented "polluter pays" principle, whereby the cost of market externalities is corrected by imposing a tax on the causers of the externality. This principle has so far not been applied to ancillary services in the NEM.

Pigou's analysis was re-visited by the American economist Ronald H. Coase in 1960. Coase showed that if property rights are clearly allocated, if parties can negotiate costlessly and there is perfect information (i.e. along the lines of the standard assumptions for a competitive market), then efficient outcomes result no matter how the law assigns responsibility for damages. In practice these idealised conditions are never realised. But Coase's analysis does suggest policy options broader than those proposed by Pigou, even though application requires analysis of each circumstance. Specifically, there may be opportunities to trade a well-defined product even where that product might initially be perceived as an externality.

Emissions trading is an example of this approach. Sulphur emissions trading is established in the US and greenhouse gas emissions trading is also mooted. To establish such a regime, a target or *standard* for the emissions must be set, probably as an upper limit on the total quantum of emissions each year. Rights to emit allocated amounts of emission are then established as well as regulatory and monitoring arrangements to enforce them. After the initial allocation of rights by a regulator, parties may trade them at a price set by supply and demand. Trading parties include those who tend to increase emissions and those who tend to decrease emissions that affect the achievement of the standard. A regulatory process is required at several points; first to establish the standard to be achieved; second, to ensure the necessary information flows; third, to define, assign and secure property rights in the products that affect the achievement of the standard; and finally, to provide oversight and take remedial action should the trading system not work adequately.

There are good prospects of applying similar concepts to FCAS and some NCAS in the longer term as outlined below. In each case the broad steps are:

- Define through some rigorous public process the standard to be achieved; this will involve an economic, social and technical analysis that will usually involve assessments of risk.
- Define and provide the necessary information requirements.
- Define a tradeable product whose production and consumption affect the achievement of the standard.
- Implement and enforce arrangements that allow this product to be traded between the interested parties.
- Define and provide arrangements for regulatory oversight and intervene should the standard be breached.

In the case of NCAS and FCAS, it can be expected that the trading arrangements will be closely integrated with the energy market in some way.

Noting the above, the following sections now consider the light on the hill and transitional arrangements for FCAS, NCAS and SRAS services respectively.

Frequency Control Ancillary Services

Overview

The distinction to be made within this group is that the small frequency deviation service is used continuously, while the large deviation service is always enabled but seldom used, and less so as the system grows larger through interconnection. FCAS are currently defined in three timeframes; 6 and 60 second for the fast-acting large deviation requirement, and 5 minutes for the slower-acting small deviation requirement. These products are generally sourced from generators and potentially from load shedding in the large deviation case. Only a limited number of potential providers have entered ancillary service contracts for the long term. The contribution from the non-dispatchable demand-side is now largely excluded.

Requiring providers to commit to FCAS offer prices well ahead of spot time, together with the limited number of providers that can be signed up long term, almost certainly increases the cost of FCAS provision and limits the competition that might be marshalled under more flexible arrangements. For this reason there is scope to enhance competition by procuring these services much closer to the time of need; in essence, in the same-day timeframe in which the energy spot market operates. This would require no fundamental change to current dispatch logic for either FCAS or energy, although additional IT communication and related facilities would be required.

Transitional Arrangements

The immediate steps and transitional arrangements proposed for FCAS include the following:

- Commence a review of FCAS product definitions[1] with a view to distinguishing more clearly the ability to respond to different frequency conditions over a range of time horizons. Pending the review of FCAS product definitions, the existing FCAS product definitions should be modified to the extent supportable within the existing SPD logic.

- Undertake a review of frequency standards and the FCAS requirements to meet those standards in a robust public process. Noting the proposed review on frequency standards[2], NEMMCO should recommend to the NECA Reliability Panel that this review include the form of frequency standards and the corresponding FCAS requirements.

- NEMMCO should procure ancillary services (small and large deviation) through an on-the-day bidding process integrated with the energy spot market. This would be done via the establishment of one-way spot markets in FCAS enablement (for each of the products that comprise the small and large scale deviation services). For each FCAS product, a common clearing price for enablement should be used in each trading interval, obtained from the SPD process just as regional energy spot prices are determined now.

- During the transition period long term contracting between NEMMCO and providers may be retained to provide any residual needs for the large deviation service. This may also include the establishment of initial vesting arrangements that would allow the FCAS enablement markets to begin with minimal financial exposures.

- In the short term there would be no additional payment for use of the small deviation service. However, additional usage costs may be incurred for the large deviation service.

These steps should increase the competition for provision of these services and drive the cost down. Procedures for charging the centrally incurred costs would still be required and will be considered in the next stage of this project.

Light on the Hill Arrangements

The light on the hill for FCAS envisages a two-way market where short term energy deviations (relative to the energy spot market and occurring within the current 5-minute dispatch period) are traded directly between the causers of deviations and those who act to correct them. This would be achieved through a pricing rule that would increase the energy

[1] The product definitions of 6 second, 60 second and 5 minute raise and lower that define the small and large deviation frequency control services.

[2] The NECA Reliability Panel is proposing to undertake an economic analysis of frequency standards in 2 years time when data is available.

deviation price when there is a short-term energy (power) deficiency and decrease it (to a negative value) when there is a short term energy (power) excess. The proposed energy deviations market would essentially add a usage component to the enabling market price. As indicated below, the enablement market would be retained but should reduce in turnover as the usage price element is increased in the small deviation market.

While there are several possible approaches, the pricing rule must be consistent with logic used for the central dispatch of plant to regulate (control) small frequency deviations. When implementing this approach:

- There would need to be a period of experimentation and testing to determine a suitable energy deviation pricing procedure.
- Use of SCADA-level data would be suitable for an initial and partial implementation. Later, specialised metering would be desirable, especially to deal with fast responses.
- Initial participation could be optional to some Market Participants at least, noting that participation would remove the obligation to pay for the "use" component of FCAS incurred under present NEMMCO arrangements.

A spot energy deviations market would offer the prospect of developing metering that would support and promote greater demand side participation.

In addition to the development of an energy deviations market, the light on the hill also envisages the following:

- Revised frequency standards determined through an economic analysis of the risks and costs associated with different levels of frequency control, bearing in mind the over-riding need to maintain a secure system.
- Revised FCAS enablement product definitions to minimise current anomalies and technology biases.
- Continuation of the spot enablement markets in FCAS proposed for the transition, although possibly with revised product definitions. As before, this market would pay a common clearing price for each FCAS enablement product as determined through a short term bidding process and the SPD co-optimisation logic. As mentioned above, when running in parallel with the energy deviations market, the dollar turnover in the FCAS enablement markets would be much less than when first established.
- FCAS providers would include non-dispatchable plant (including flexible loads). Provider facilities could be embedded deep within distribution networks and provide services in addition to FCAS.
- No requirement for long term contracting by NEMMCO in the small deviation service, although this may be required for the large deviation service.
- Potential FCAS providers would need to register their capability with NEMMCO.

Network Control Ancillary Services

Overview

Generally, NCAS improves the network's ability to transfer energy (power) within secure operating limits. These limits are complex and have many technical dimensions. Relatively few of them currently have sustained current or potential significance for energy trading; most are intended to deal with particular network outage conditions.

In the NEM, these network limits are identified and defined by NEMMCO and Network Service Providers (NSPs) by means of technical studies. Those relevant to the spot market energy dispatch over the transmission network are then expressed in mathematical form and used to limit the pattern of dispatch arising from the bidding and system pricing and dispatch (SPD) process. The limits imposed on the SPD depend on the ancillary services available and the way NEMMCO had dispatched them. *Currently there is no automatic process that compares the costs of enabling these services with the value that these services provide to the energy market.*

The SPD logic has an in-built mechanism to shadow price the ancillary services that affect each network limit. Each shadow price values the benefits to trade in the energy spot market of a marginal increase in the provision of the relevant NCAS. The validity of these shadow prices depends on the adequacy of the underlying network model in modelling the physical system and, even more strongly, on the robustness of the constraints imposed to manage network risks, which incorporate many judgements. Accepting this, it is possible to draw a direct relationship between the provision of NCAS and energy market trade, in a way that could support two-way trade between some NCAS providers and Market Participants in the energy market. Such trade could be on a spot basis or by longer-term bilateral negotiation.

NCAS makes up around 25% of total ancillary service costs. Most NCAS are geographically specific. This may in some cases limit the scope for competition in the immediate future. While both NEMMCO and TNSPs currently have responsibilities to procure such services in the NEM, alternative buyers could be entrepreneurial NSPs interested in increasing network capability. Thus the prospects for two-way markets in these areas depend to a significant extent on how the reform of network pricing progresses, as noted earlier.

In any new arrangements, NEMMCO would remain responsible for dispatch, spot pricing and power system security. Within this framework, parties (such as Market Participants, TNSPs and NEMMCO) may contract for NCAS services for the purposes of hedging and procurement.

Transition Arrangements

Initially, significant improvements could be made with the following strategy, which essentially defines the transition to the light on the hill for NCAS. These arrangements and developments follow.

- For the short term, current procurement and dispatch arrangements should remain for all NCAS services, subject to changes that might arise from the "who pays and how much" phase of this project.
- Initial arrangements for voltage control (contingency and continuous) services are proposed as follows:
    - As indicated in the overview section, NEMMCO would remain responsible for the dispatch of voltage control services and for ensuring that there are sufficient voltage control services from a power system security perspective.
    - Contracts (for hedging/procurement) would be written between generators and TNSPs / NEMMCO depending on the clarification of responsibilities for reactive reserve.
    - For reactive generation that is required due to the connection of a generator and that is consequently specified in a connection agreement, no cost associated with reactive reserve. For reactive above this level, negotiated contracts that specify availability and enablement components. Compensation to be payable if generating plant needs to be backed off to provide the reactive service.
    - Although testing of an AC load flow nodal pricing model that would price reactive energy in the context of energy spot trading is proposed, the co-dispatch of generator reactive capability with the energy spot market may not be warranted or feasible in the transitional phase.
- Initial arrangements for Stability and Network Offloading services are proposed as follows:
    - Negotiated contracts are recommended as the most appropriate arrangement for procuring stability and network loading services for the foreseeable future.
    - The arrangements would require NEMMCO to provide information on potential schemes and the service that they would provide. This would need to be included in the Statement of Opportunities.
- Further consideration of markets in NCAS should be preceded by a review of the basis for and structure of the currently defined generic (security) constraints applied in the SPD.
- NEMMCO should extract and publish the pattern of shadow prices and related information associated with each (or at least the most significant) generic constraint used in the SPD process. NEMMCO should take account of these shadow prices when determining the appropriate quantum to acquire in its contract tenders and negotiations.
- After investigation on a case by case basis and if feasible and desirable given market power and materiality considerations, NCAS dispatch and pricing should be integrated with the spot energy market using the shadow pricing logic previously described. As a first step to this development, consideration should be given to integrating with the energy spot market those constraints that can be most readily and easily implemented.

- Regardless of whether a service is procured by competitive tender or through a spot market, NEMMCO should stand aside to allow other parties to contract (ie. hedge/procure) with NCAS providers should the transmission pricing regime support such entrepreneurial activity. NEMMCO would still dispatch and price the services through the SPD logic.

Light on the Hill Arrangements

Some NCAS are likely to be more amenable to competitive arrangements than others, or require specific measures to “level the playing field”, whether or not a market can be developed for them. There are prospects for early implementation of enhanced spot trading by recognising that energy dispatch affecting constraints would require few additional IT facilities. Particular recommendations for individual services are as follows.

- Voltage Control Contingency:

  The most likely NCAS service for competitive provision, based on materiality and other considerations, is the voltage contingency service, which also covers some of the peak period component of the continuous voltage control service. Levelling the playing field for this service would require formal recognition that potential (reactive power) providers should be treated on an equal basis. At the moment the potential for competition in voltage control services is clouded by apparent Code inconsistencies that assign responsibilities to both the TNSPs and NEMMCO, and that relate to the different incentives that apply to TNSPs, DBs and generators in respect to these services. Particular issues relate to the inclusion of TNSP voltage control services in the regulated asset base (in accordance with TNSP planning criteria), and the lack of pricing signals for DBs to control reactive withdrawals (although the Code does provide power factor standards that can form the basis for TNSPs and DBs to co-operate in the provision of reactive sources such as capacitor banks).

  The arrangements proposed for this service are:

  - NEMMCO would define and manage the security constraints that define the terms of trade in this service.

  - NEMMCO would dispatch, price and settle the provision of reactive capability and reactive consumption through the generic constraint logic in the SPD process as described earlier in this section.

  - Long term procurement would be organised through two-way trade between reactive providers, consumers and parties who have an entrepreneurial interest in maintaining secure network capability for the purposes of energy trade.

  - Static and dynamic reactive capability may, in some cases, need to be distinguished as separate products. Continuous reactive at peak times would also be priced under this arrangement as the constraints are likely to be defined in terms of total capability, which will include continuous provision.

- Voltage Control Continuous:

  The continuous voltage service requires the apparent anomalies outlined above to be corrected, including more investigation of pricing approaches. Parallel operation and testing of an AC load flow nodal pricing model that would price reactive energy in the context of energy spot trading is proposed and could be a first step.

- Stability and Network Offloading:

  These services would involve implementing formal procedures for generic constraint review and shadow pricing as recommended. Depending on assessments of feasibility or progress with the introduction of arrangements for entrepreneurial network development, introduce two-way as arrangements as described. Such arrangements are likely to involve negotiation based on long term contracts rather than short term short term / spot trading.

- Spot Trading Benefits:

  The development of this service would also involve implementing the formal procedures for generic constraint review and shadow pricing (as previously recommended). Spot trading benefits would be captured through the use of the existing bid arrangements for dispatchable plant and relaxing the dispatch variables in all constraints where they appear. Settlement should report each constraint transaction.

  The ultimate vision is based on a more accurate network model that would replace the current transportation model in the SPD with a full AC loadflow model. This would improve the benefits of trade and improve prospects for pricing and managing the continuous voltage control service.

System Restart Ancillary Services

There are no prospects for two-way trade in this service but there is scope for making provision more competitive and robust against the range of “system black” conditions that could occur at various levels in the system. There is a need to recognise and make maximum use of embedded facilities that may be maintained and used (and therefore tested) from time to time in other duties. The main recommendation is to develop a strategy for system re-start, co-ordinated with more local needs, such as emergency supply for major city centres, consistent with the policies developed by the NECA Reliability Panel.

Code Changes

Code changes including the following would be required to implement the full recommendations of this report. The list does not include some higher level changes that might be desirable after further review, including those relating to the definition of security and reliability standards.

- Define the spot market in FCAS enablement (with perhaps daily bidding) for early implementation.

- Define the objectives and broad approach to the light on the hill for each group of services, in sufficient detail to allow implementation with reasonable flexibility in timing and extent, and noting the milestones to be achieved on the way.

- Formalise and extend the role of the NECA Reliability Panel in co-ordinating regular reviews of frequency control standards, network reliability standards, power system security standards and system restart policies within a risk / economic cost benefit framework.

- Pending consideration of the Code anomalies and the development of light on the hill arrangements in voltage control services, remove TNSP reactive facilities from the regulated rate base and oblige NEMMCO to consider TNSP and DNSP reactive production and consumption explicitly and equally in procurement and pricing of both NCAS and FCAS.

- Pending ancillary service arrangements, remove mandatory provision clauses.

Priorities

The broad implementation priorities in chronological order are:

1. Proceed with consultations and Code changes to support the changes outlined.

2. Implement the spot market in FCAS enablement as a top priority to meet the immediate requirements of the ACCC and to gain the benefits of further competition.

3. Enhance the Reliability Panel's role to oversight the following tasks, using open and robust public processes and recognising the fundamental role of the demand-side in the provision and consumption of all of these services:

    - review of frequency and time error standards;

    - review of the basis for the setting of specific generic constraints, with a priority on those constraints which have the greatest impact on spot trading; and

    - review of system restart strategies, noting the relationship between the facilities required to meet local needs and those required to meet needs at a higher level.

4. Implement Code changes to ensure that currently regulated network facilities, retailers, distributors and end users that participate in ancillary service provision and consumption are treated on a non-discriminatory basis in relation to the provision of ancillary services.

5. Investigate the following for implementation in the longer term, taking into account the results of Reliability Panel deliberations:

    - a redefinition of FCAS enablement product categories to remove technological biases and current anomalies;

    - adjustments to the SPD that would dynamically determine the requirement for the large frequency deviation FCAS based on the pattern of dispatch;

- an optional energy deviations market to supplement the spot market in FCAS, to allow participation by non-dispatchable loads as well as dispatchable plant;
- the trading of selected NCAS through the operations of generic constraints in the energy spot market SPD, focussing initially on the voltage-contingency service and on opportunities for enhanced spot trading involving existing energy bids and offers;
- enhanced spot trading and improved pricing and possible trading of the continuous voltage control services, through the development and operation in parallel with the SPD of a pricing model based on AC loadflow analysis.

TABLE OF CONTENTS

1 Introduction

1.1 The Brief

The Ancillary Services Reference Group (ASRG) established by NEMMCO has commissioned Intelligent Energy Systems (IES) to assist it with a review of ancillary services in the National Electricity Market (NEM). This review was a requirement of the ACCC's final determination on the National Electricity Code (Refs 2&5). It is required to address the possibility of developing market-based arrangements in ancillary services, including a short-term market. The new ancillary services regime was to be in place from 1 July 1999 but the ACCC has now granted an extension. The brief was to be conducted in two phases:

- Phase 1 would review the framework established by the ASRG, and then evaluate the different ancillary services and advise appropriate arrangements;

- Phase 2 would address the mechanism for "who pays and how much" for the various ancillary services, *and will be the subject of a separate request for tender*.

IES completed its review of the Framework established by the ASRG in late 1998 and the revised ancillary services Framework document is now available on the NEMMCO web site (Ref 1). The current report relates to the second part of Phase 1. The terms of reference for this evaluation stage are reproduced below:

"Using the ASRG Principles, and the agreed Framework as described in the final framework report, the consultants are required to undertake the following for each ancillary service identified:

Ancillary Service Market Design:

- An evaluation of the alternative arrangements for provision of the service in accordance with the ancillary services classification criteria, i.e.
    - spot market;
    - contracts; or
    - mandatory;
- Where market based arrangements are identified as appropriate through the ancillary services classification criteria, a detailed description of the most appropriate method for structuring these market arrangements (including consideration of transaction costs versus benefits);
- Where market based arrangements are identified as not appropriate through the ancillary services classification criteria, identify and evaluate alternate methods for procuring these ancillary services;
- Advise on procurement, dispatch and pricing in keeping with the ASRG Principles.

Non Competitive in Pockets:

- Advise on specific arrangements for services which are identified through the ancillary services classification criteria as being appropriately provided by market based arrangements, but found to be non competitive in pockets (due to geography etc). These arrangements must be consistent with the overall ancillary services market design for each ancillary service.

The consultants should also recommend implementation and, where appropriate, transition arrangements for procurement, dispatch and pricing.

In addition, the consultants should comment on the methodology used by NEMMCO for determining the quantity of each ancillary service to be procured consistent with the prescribed standards in the Code and from the Reliability Panel."

The brief placed emphasis on developing an approach for the longer term that the ASRG termed the light on the hill, together with appropriate implementation and transition arrangements. We interpret the light on the hill to include possibilities that show promise in terms of their consistency with the objectives of the review. Some of these may not yet be fully explored, given the time limits set by the ACCC, and may not in every case be able to command a full consensus in the first instance. However, the ASRG clearly expects to see a workable path forward, including early implementation of the more prospective market arrangements.

The brief explicitly excludes the question of "who pays and how much" which is the subject of another brief. This exclusion appears to rest on the assumption of a central procurement model, the brief being primarily concerned with improving the level of competition in the procurement process. However, we have not adopted this narrow stance because there are some market options that could involve both buyers and sellers of some ancillary services operating within a framework managed by NEMMCO (the market operator), but without NEMMCO having direct involvement in every transaction. For this reason the question of "who pays and how much" will arise in this report but, to the extent possible, we refrain from reaching a conclusion on the matter.

Gavan McDonell & Company, P. M Garlick & Associates, Associate Professor Hugh Outhred and Mr Rod Frowd have joined with IES in this project. However, the final content of the report including all errors are the responsibility of IES.

1.2 ASRG Ancillary Services Framework

The key reference for this project is the ASRG's "Framework for the Development of an Ancillary Services Market to Support the National Electricity Market" ("the Framework", Ref. 1). The principal parts are:

- Regulatory Background and Economic Concepts;
- Principles of Ancillary Services Review;

- Ancillary Services Description; and
- Ancillary Services Classification Matrix.

The regulatory background, economic concepts, principles and technical descriptions will not be repeated in detail here, but will be referred to and developed though this report. However, for completeness we re-list the ancillary services defined in the Framework and impose a broad grouping that we will use throughout this report.

- Ancillary services concerned with the balancing of power supply and demand over short time intervals throughout the whole system; the ***Frequency Control Ancillary Services (FCAS)****:*
  - Frequency management – small deviations; and
  - Frequency management – large deviations;

  Note: Time error management is included in the above.
- Ancillary services concerned with maintaining and extending the operational efficiency and capability of the network within secure operating limits; the ***Network Control Ancillary Services (NCAS):***
  - Voltage control – continuous;
  - Voltage control – contingency;
  - Stability control;
  - Network loading contingency control; and
  - Spot market trading benefits.
- The Ancillary Service concerned with recovery from a partial or total power system failure; the ***System Restart Ancillary Service (SRAS):***
  - System restart.

The current and likely future arrangements for managing these technical issues are complex and have been described in the Framework document. The technical and commercial options are often many and widespread. For example, a standby generation facility embedded in the distribution network could potentially provide services to each ancillary service group simultaneously, noting that many such services relate to the capability to respond to contingencies in the system. In the voltage control area, reactive power capability can be provided by generators, end users and distribution and transmission networks with a range of equipment, although choice can be constrained by geography. The present Code provisions and accountabilities in each case are complex and, as will be seen, not entirely clear or consistent in every case.

These groups can potentially interact in a number of ways, but the distinctions are useful for exposition in this report. Unbundling these services is a first step towards commercial provision and, ultimately in some cases, their competitive provision through markets.

The ASRG's classification is also different to that currently used in the NEM. It is an attempt to remove some of the more technology-specific elements in the current arrangements to better satisfy the ASRG Principle of technology neutrality (which in turn is intended to widen the scope for competition). It is also different to that used elsewhere, most notably that used in the US that will be reviewed later in this report. It is, however, clear that the classification of ancillary services throughout the world is by no means a settled matter. While there are some constant and unavoidable themes arising from the fundamentals of the technology being addressed, the approaches used are also highly geared to institutional and competitive arrangements. The groupings, as the names suggest, reflect a commonality in the *application* of the ASRG defined services that will aid analysis throughout this report.

1.3 The Significance of Ancillary Services in the NEM

NEMMCO has provided rough estimates of its expectations for the cost of ancillary services in the NEM over 12 months under the current arrangements and with currently active contracts as $95 million per annum for the inter-connected NSW/Vic/SA system and about $35 million per annum for Queensland[3]. Relative to prices in the energy spot market this represents around 3% of turnover but probably little more than 1% for the industry as a whole. In the context of the whole industry, therefore, the cost is expected to be small. On the other hand, it is more significant in the context of the energy spot market.

However, noting that retailers currently pay for these services on a cost-as incurred basis, and that retailer margins are considered to be as little as 2%, these costs represent a very significant financial management problem for retailers. This is especially so if the costs turn out to be volatile and if, as at present, the arrangements are not conducive to hedging or other risk management measures.

This background suggests that the ability to manage the risks of ancillary services is likely to assume a high priority for retailers. As retailers essentially pass on purchase costs with a margin, they are likely to rank cost certainty ahead of the absolute cost. On the other hand, generators and others will naturally seek to maximise the return from all their business activities, including the provision of ancillary services, and perhaps more than current estimates of total ancillary service costs might indicate[4]. Finally and critically, the end-user, and the ACCC and state regulatory bodies on their behalf, is interested in efficiency as that will generally translate to lower end-user costs. These tensions present a particular challenge for the design of Ancillary Service arrangements.

[3] Queensland is currently operating under different ancillary service arrangements than the other states.

[4] The desire is not the same as achievement, which highlights the importance of competitive discipline even when current costs seem to be low.

The breakdown of costs between particular services is made difficult by the lack of experience in the NEM to date. Estimates supplied to IES by NEMMCO suggest the following:

Estimated Breakdown of Ancillary Service Costs by Group for 1999	
Frequency Control Ancillary Services	**65%**
Network Control Ancillary Services	**25%**
System Restart Ancillary Service	**10%**
Source: NEMMCO	

All but a few million of the estimated cost of FCAS is for services currently provided by generation facilities[5], By far the dominant cost in the NCAS group is reactive power or capability for voltage control (continuous and contingency). With SRAS at 10%, FCAS, the reactive component of NCAS and SRAS together are estimated to make up 95% of the current cost of ancillary services. These will clearly be the prime focus of attention in this report. *However, we recognise that currently low costs are not necessarily an indication for the future, and that the Spot Market Trading Benefits service as defined in the Framework is not included in the current NEM Ancillary Service arrangements. For this reason it is important that arrangements recognise the possibility of a change in these relativities.*

Indicative figures provided to IES by NEMMCO for the first few weeks of the NEM confirm the broad break-up described above. However, initial indications are that some elements are rather volatile, one being the compensation component of FCAS (to be described later, but which tends to reflect the volatility of energy spot prices) and this has also been particularly noticeable in the volatile spot market environment in Queensland. This volatility suggests that there will be a premium on arrangements that can reduce this spot-price related volatility in FCAS, or which at least make the risks associated with these costs easier to manage.

It is important to note that these estimates do not include the costs of ancillary services required or desirable to support distribution networks. Most end-user supply interruptions and a substantial part of end-user costs relate to the distribution network. As will be noted later, many of the services that could be provided to support the distribution network would not be diminished if they supported the larger system as well.

1.4 Approach taken in this Report

Under the previous centralised regime the integrated utility defined and provided a set of operations, commonly called ‘ancillary services’, the purpose of which was to keep the power system operating stably within prescribed standards of security and, in some respects, Quality of Supply (QoS). QoS here refers to the production of electrical energy with characteristics,

[5] This possibly reflects a relative low proportion of load shedding options that would deal with contingencies. The contracted providers are evidently sufficient to deal with small as well as most large contingencies.

notably of frequency, voltage and waveform that make it of 'useable' quality to end-users. The assumption is that the security and basic quality criteria form a discrete bundle, capable of unique definition, necessary for maintaining the operating integrity of the system. This assumption is discussed further below.

Above the standards regarded as being technically required to meet security needs - standards that have been largely carried forward from the previous regime - QoS can be varied in a way that might be differentially attractive (useful) to producers or consumers of electricity. This is also discussed further below.

Under the design of the NEM, the system control functions of the previous integrated utilities were replaced by a separation of functions into those allotted to:

- the market manager/regulator, NEMMCO, essentially required to ensure the provision and maintenance of market arrangements in accordance with the approved provisions of the Code; and
- the system administrator/regulator, NECA, essentially required to administer the Code arrangements other than those of market management and to coordinate Code change processes.

The primary exchange of tradeable goods by Market Participants (in the spot market restricted at present to electrical energy) is thus functionally and legally separated from the provision, maintenance and regulation of a secure and reliable market system (SRMS), which are the responsibilities of NEMMCO and NECA.

The criteria for ancillary services were expressed technically and taken over by NEMMCO pretty much as they had stood, but now specified as requirements under the Code necessary for the provision of a SRMS. That is, they have been obtained by the centralised market manager/regulator to satisfy prescribed regulatory standards of security. It is to be noted that they are not regarded as providing quality standards affecting the merchantable quality of goods above a basic standard assumed to be necessary for all participants. As discussed further below, there are ambivalences related both to the need for and precision of the system security standards and to the requirements for the associated basic standard of 'quality of goods' which complicate the transformation of the existing arrangements into some forms of competitive markets.

Under the arrangements now in place, NEMMCO, as the central, monopsonistic buyer of ancillary services, acquires the defined services through:

- utilisation of resources available to NEMMCO under the mandatory provisions of the Code and connection agreements;
- competitive tenders where there are competing providers (who, to date, with the exception of interruptible loads, have been energy suppliers in the energy spot market);

- negotiated contracts where competition is insufficiently effective because the potential provider(s) of the service have market power, either generally or because of spatial considerations; and
- direction, if necessary and as a last resort.

NEMMCO acquires and deploys the services according to the needs assessed to meet the stipulated standards criteria, and the payments required for that are then subsequently charged to Customers who are loads as they are incurred. The general situation is that only energy spot market buyers are expected to pay for ancillary services.

Thus, the current model for the provision of ancillary services in the NEM is that of a central operator procuring resources necessary to maintain set system standards of security without reference to whatever it was that caused the need for each service, and then levying charges on the purchasers of the primary traded good.

In its approval of the relevant provisions in the Code, the ACCC said:

'Ancillary services are services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure electricity supplies are of an acceptable quality. Schedule 9G sets out the ancillary service provisions that are to apply in the NEM until 1 July 1999 (*ie, broadly as described above*). Schedule 9G will over-ride the provisions of clause 3.11 of the Code, with the exception of clause 3.11.1(c), which states that NEMMCO must:

'investigate, consult with Code participants in accordance with the Code consultation procedures and report to NECA by 1 March 1999 on the possible development of market based arrangements for the provision of ancillary services, including a short term market in which Market Participants which are not parties to ancillary services agreements may submit offers for the provision of regulating capability or contingency capacity reserve.'

In addition to the comments above, the ACCC also said in its Determination that

'it therefore appears to be inherently inequitable that only buyers are expected to pay for the provision of such services... the Commission considers that the best signals will be sent to the market if the fee recovery model allocates costs to those who caused the need for ancillary services or, if that is not feasible, then charges for those services should be based on the benefit received, perhaps determined by reference to energy transactions in the market.'

It further commented that:

'…the Commission understands that the NEMMCO review of ancillary services will consider the issue of mandatory services ...'

As noted above, purchasing of ancillary services is now based on a form of competitive tender, which is conducted months ahead of the time of need, or through a negotiation process which attempts to take into account the anti-competitive effects of market power. Thus, there is already a form of competitive market. The term 'market based arrangements' used by the

ACCC could be, and, we believe, generally is, interpreted in this context simply to imply a new system, involving a one sided market with a single buyer, NEMMCO. NEMMCO would purchase the services assessed as required to maintain the stipulated system regulatory standards of security, through a more flexible market than applies now. This market would allow access and participation by a larger number of suppliers, including those not parties to long term ancillary service agreements. If this were feasible it would be expected to lead to lower costs and, perhaps, better services. Under such a system, the costs incurred by NEMMCO though procurement in the competitive market-based arrangements could then be allocated through charges according to some new decision rules. These rules would need to be defined and negotiated, and would take into account those who cause the need for each service or benefit from its supply.

In this model, the emphasis would be on improving the present system by reducing service costs through more effective competition, and then on devising arrangements which allow the manager/regulator to better allot the service costs according to those who cause their need and/or those who benefit from them.

There is another possible model, however which might be relevant to the development of market arrangements in the future – the light on the hill referred to in the brief. This model displays crucial differences from the case above, which is the situation as usually conceived. In essence, once system security standards are set there is a possibility of a two-way trade in the products that affect the achievement of that standard[6].

We note, for example that the need for the small frequency deviation management ancillary service (a component of FCAS) arises from continuously varying imbalances between energy demand and supply (hence the term commonly applied to these services as 'load-following'). This continuously changing situation would necessarily imply instantaneous changes in price in a competitive energy market if there were a real-time pricing system in place. Contrast this with the pricing arrangements of the constructed half hour price based on 5-minute interval auction prices, which now mediates the buying and selling of electricity. Therefore, in such a real-time pricing system, the real-time price associated with the frequency deviation represents the marginal value in the market of restoring the balance. This price, then, would be the value to market participants of a service that restored that balance.

A similar argument can be made for NCAS. We argue later in this report that *NCAS can be regarded as facilities that maintain a desired level of network efficiency and capability within a set security standard, that standard being defined as the ability to sustain a single*

[6] The concepts outlined here are similar to those behind emissions trading regimes of the kind under consideration for the management of greenhouse gasses. In essence, a standard is centrally set by some means (this inevitably being a centralised decision) and arrangements established to allow trade in rights that are defined to ensure that the set standard is achieved. The focus is on trading among the causers and the fixers of greenhouse emissions, rather than on the beneficiaries who are perhaps not readily identified except in a very broad sense. The price of the rights has the usual market interpretation, but can also be interpreted as the marginal cost (in terms of the use of society's economic resources) associated with a change in the emission standard. This is useful information when considering the merits of possible changes to the standard.

contingency, rather than a specified network transfer capability. With this view there is an identifiable economic trade-off between the cost of providing those services and the value of improving the network capability, as expressed in the energy spot market[7]. Given that these trade-offs can be quantified to an acceptable degree[8], this leads to the possibility of two-way trade in the factors, including ancillary services that affect the supply and demand of network capability within the defined security standard. Further, such an approach would begin to assign an economic cost associated with some relaxation or tightening of that standard, that might justify a modification to the standard in particular cases.

The potential for two-way trade described above does not, of course, imply that competitive arrangements are desirable or even possible in every case. Workable competitive markets require more stringent requirements to be met, as will be described in this report. Nevertheless, it is relevant to any arrangement that, with this viewpoint, the economic nature of what was previously regarded as an ancillary service has been changed. The services that provide a supply/demand balancing function or which relieve network constraints are no longer regarded simply as the *capability to maintain regulatory standards,* capabilities procured in *one-way* markets by the manager/regulator and then charged according to some administrative decision rule. They are now, potentially at least, *tradeable goods* being bought and sold by Market Participants in *two-way markets* in which the manager/regulator is not directly operating as a participant, but merely defining the basis for trade.

Three points should be noted here. First, the possibility of such an arrangement depends upon the services not having strong public good characteristics, ie, non-diminishability (free rider), excludability and rejectability, since then they would not be tradeable. Second, buyers or sellers of energy might technically not be able to 'follow the market' instantaneously. Thirdly, it is assumed that the frequency deviation or network constraint relief is within clearly and uniquely defined security standards applicable to the particular situation.

Our broad approach to the task can now be summarised. First, we recognise that there are significant opportunities in the short term to improve the competitiveness of the procurement and pricing process in some services, most notably in FCAS which is by far the largest cost element in the ancillary service mix. Our recommendations here would comprise what might be achievable relatively quickly to meet the essence of the ACCC timetable. Next, we describe a light on the hill which is the prospect of competitive two away arrangements in FCAS and at least some NCAS, as well as a transition path. We see these approaches as complementary rather than as mutually exclusive. Thus it would not be strictly necessary to achieve an early agreed position on the longer-term propositions. Indeed, such full agreement seems unlikely and unnecessary, although agreement to the broad thrust and to proceed with some initial steps would be required. These concepts are likely to be relevant to the separate brief on "who pays and how much".

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[7] The means by which this value is expressed will be examined later in this report.

[8] This depending on a range of factors including the accuracy and useability of the network model embedded in the NEM's system pricing and dispatch logic.

We conclude this sub-section with a brief discussion of some issues that will affect the approach taken in this report. The first is to note that ancillary services as defined in this brief have a strong relationship with other parts of, and activities in, the NEM.

- *Retailer, distributor and end-user interfaces with the NEM market operations and the transmission system*

  While the review has a clear focus on the operations of the spot market and the transmission system, activities within the distribution system (including activities of retailers and end users) are affected both in terms of provision of and, potentially, as beneficiaries of these services. Specifically, load management and load interruptibility, as well as the management near the point of consumption of reactive power for voltage control and loss reduction, are services that have applicability both to the transmission and the distribution system. The ancillary services Framework requires that these options be treated in the same way as other options for the provision of ancillary services.

  Further, end users are affected by QoS. Frequency and time error are QoS issues that are particularly affected by activities in the NEM as a whole. However, local voltage, wave-form, phase balance and supply availability are, in the main, matters that can and must be managed near the points of use, mostly but not always deeply embedded within the distribution system and irrespective of what might be happening for other reasons further up the production chain. The QoS aspect of frequency will be discussed later in this report. However, in terms of the management of the system for which NEMMCO is accountable, QoS is secondary to security.

- *Market top end*

  The provision of most forms of ancillary services interfaces closely with the "top end" of the energy market. This occurs because the "need" for such services becomes most pressing at times of tight supply, for example to maintain network transfer capability at times of high load. Further, they are often jointly produced with energy, such as in the case of various forms of FCAS which need "room" to operate within the generator capability and which therefore might require energy production to be backed off. It is conceivable that an approach that undervalues ancillary services and that relies heavily on mandatory provision might result in more intervention, and associated intervention costs, to deal with the maintenance of system security. As noted below, the relationship is probably most relevant when considering the question of "who pays and how much" for ancillary services. This issue is also relevant to a current NECA review of capacity mechanisms in the NEM (4).

- *Network pricing & investment*

  The services that we have grouped as NCAS interact strongly with network regulation, pricing, investment, inter-regional trade and hedging, and the concept of firm access. This has long been a contentious area in the NEM and is currently the subject of a major NECA review (3). In this report we will note the connection at many points, and our recommendations will try to be sympathetic with, and support, how regulation of the networks might move in future.

Finally, we outline our approach to the matter of the mandatory provision of services. Technical capability relevant to the provision of some ancillary services is currently *mandated* by the Code or through connection agreements. It might be argued that provision of the corresponding service should therefore be set aside from any possible market or other arrangement that might be established. We have not taken this approach, for several reasons.

- Firstly, the requirement to have a governor or a certain reactive capability in a generator does not in general guarantee that the facility will be available for use by NEMMCO. Specifically, a unit may be off-line, even though its presence on line might be of great value. If direction is to be avoided wherever possible (which we take to be a given), some means must be found to ensure that the service is willingly made available if needed.

- Secondly, a mandatory facility can be regarded simply as one subject to a negotiated contract where there is no payment made to the provider. In fact, under most of the arrangements proposed in this report, the status quo can be reproduced closely though the use of contracts, even when a spot market or even real time market may be operating.

- Finally, we think that a decision to mandate some services (i.e. have them provided at no attributable cost) has implications for long run dynamic efficiency. Specifically, a lack of income by generators or other participants for the provision of such services is likely to raise the threshold of investment for new plant, especially peaking and emergency plant. This could exacerbate the so-called “top end” problem, an issue currently being considered by NECA in its review of capacity remuneration in the NEM. We will not come to a view on this in the current report, but it is pertinent to the issue of “who pays and how much” for ancillary services and should be considered in that study.

1.5 Report Outline

Section 2 outlines the operation of the current NEM and, in particular, the operation of system pricing and dispatch and the current arrangements relating to ancillary services. This background is necessary to support both the light on the hill arrangements as well as shorter term proposals and the transition. Experience overseas is also reviewed, focussing on the US FERC determinations on ancillary services as well as the approach used in California. It concludes with a summary and assessment of the range of approaches that might be considered for the NEM.

Section 3 discusses the broad considerations that apply to the FCAS group of services, and outlines approaches for short term market development as well as outlining the light on the hill. Section 4 doers a similar task for NCAS and Section 5 for SRAS.

Section 6 summarises the light on the hill for broad service groups defined. Section 7 summarises the proposed approach to implementation, including the transition path.

The Appendices include further detail and examples.

2 Approaches to Ancillary Services

2.1 Overview

In Section 2 we review the current treatment of ancillary services in the NEM, including recent experience with their procurement through the tender process carried out in 1998. This includes background on the operation of the energy spot market, including the process for scheduling, pricing and dispatch through the SPD model. Queensland currently has slightly different arrangements that are also described. We then review current practice and experience in the USA and New Zealand. This is followed by a discussion of an alternative approach that would, to the extent that it can be applied, establish two-way markets in these services in close association with the energy spot market. The section concludes with an initial comparative assessment of the approaches.

2.2 Current Energy and Ancillary Service Arrangements in the NEM

The current regulatory arrangements for the provision of energy and ancillary services in the NEM were outlined in the Introduction. In this sub-section we describe some of the procedures in more detail to provide background for the discussion and analysis that follows.

2.2.1 Energy Market Pricing and Dispatch

The 5 minute dispatch and pricing process

NEMMCO runs a process called Scheduling, Pricing and Dispatch (SPD) every 5 minutes (although the dispatch takes place continuously). *Scheduling and Pricing* is done by matching a set of bids and offers with electricity demand using the logic described below. *Dispatch* is the process of translating the operating schedule that comes from that logic into operational outcomes.

- Market Participants with *dispatchable* plant (mostly generators) submit offers to the market operator (NEMMCO) which describe how much they are prepared to generate (or reduce consumption) in up to 10 price bands. A plant is dispatchable if it can be instructed to operate at a given level of power output (more or less) following the acceptance or otherwise of its offers into the market. Most loads are not dispatchable; they are the aggregate outcome of end-users doing what they do without reference to NEMMCO or a centralised process. This approach reflects a judgement made when the NEM Code was written, and later approved by the ACCC, that centralised pricing and dispatch of the energy spot market was the way to operate the Australian NEM.

- NEMMCO uses the following information to produce a schedule of energy market-clearing prices in each region (and for other services as described later) as well as a schedule of proposed operation of dispatchable plant:

  - the bids and offers of Market Participants described above;

- technical characteristics of the dispatchable plant (capacity, ramping capability)[9];
- NEMMCO's assessment of load over the following 5 minutes;
- a model of the transmission network, which models inter-regional and intra-regional losses and operational constraints in a simplified way;
- various other elements, some of which relate to ancillary services as described below;
- a spot market clearing objective which is, in essence, to maximise the benefits of trade over the network.

- The tool used to do this is a linear programming model embedded in the NEMMCO's SPD software, the requirements for which are set out in Chapter 3 of the Code. The essence of a linear programming solution of this problem is that:
  - all the defined physical and policy constraints are satisfied (if possible to do so);
  - the objective - in essence to maximise the benefits of trade with the defined offers and bids and other constraints - is achieved;
  - an operating schedule for each item of plant is produced (essentially to ramp up or down to a defined degree);
  - a schedule of shadow prices is produced, which describe how much the objective would change for a unit change in any factor that affects a constraint. *Specifically, the shadow prices associated with each regional energy balance constraint in each region is defined as the regional price, as it can be shown that this shadow price satisfies the requirements of the Code.* The SPD solution contains other shadow prices that are not currently used.
- The schedule from the SPD includes target production for dispatchable plant that reflects assessed ramping capability over the next 5 minutes. As described later, the schedule also includes plant enabled to provide some ancillary services, namely FCAS. This schedule is then fed into a NEMMCO facility called Automatic Generation Control (AGC) and related communications and management facilities that performs the following functions:
  - notifies Market Participants of their target operating levels over the next 5 minutes;
  - sends out "raise" and "lower" signals (that actuate local controllers) to each generating unit to achieve the targets at the required rate (at intervals in the order of seconds);
  - monitors the frequency behaviour in the system to assess any emerging deficiencies or excess of power production;

[9] These technical characteristics are vastly simpler than those that apply in the England and Wales electricity market and in the initial Victorian market. This simplification reflects a goal of the NEM (and the Framework that guides this brief) to maintain independence from technology.

- sends out incremental "raise" and "lower" signals to each generating unit that is also enabled to provide the "regulation" or small deviation FCAS; this signal adds to or decrements the signal sent out to implement the energy spot market outcome.

- The sequence of 5-minute energy prices obtained in this way is averaged at the end of each half-hour to produce the half-hourly market price, which is the price at which energy market transactions during the half-hour are settled (after allowing for losses).

FCAS co-dispatch logic

The SPD model already has embedded within it some sub-models for dispatching various classes of FCAS. This is built around 6 broad classes of FCAS; namely:

- 6 second raise and lower;
- 60 second raise and lower; and
- 5 minute raise and lower.

Some facilities for load shedding are also provided. The first two sets (4 services) above and any load shedding meet the requirements for large frequency deviation management as defined in the Framework. The last set (two services) is used to control small frequency deviations as defined in the Framework, the so-called *regulation* function. The quantum of service required is externally determined by NEMMCO based on the frequency standards established by the NECA Reliability Panel.

An important question is why it is considered necessary to include FCAS within the energy spot market SPD model. The argument in favour is that there is a strong relationship between production of FCAS and energy; they are joint products of generation and of some other facilities as well[10]. This implies that there is sometimes a trade-off to be made between the two, and the presumption is that the trade-off in the Australian NEM is best done centrally. This is a debateable proposition that will be examined at the end of this section. We note that Principle (iv) (b) of the Framework states that co-dispatch (i.e. optimised joint dispatch) of ancillary services with the energy market should be used wherever possible.

While the co-dispatch logic for FCAS does produce a shadow price for each service, unlike the shadow price for energy in each region, it is not used for settlement purposes. Instead, long-term contract prices are paid, together with an adjustment of the amount a unit is assessed to have lost by not operating in the energy market.

The current position in Queensland is different. There, an ancillary service optimisation is carried out separately from the energy market, with the objective of providing the required quantum of service for the least compensation, given the compensation rules.

[10] For example, FCAS in the form of load shedding is jointly produced with whatever the load is normally assigned to do i.e. to drive a dragline, water pump or smelter.

Generic constraints

There is a class of constraints imposed in the SPD that are intended to ensure that the dispatch pattern and resulting flows over the transmission network remain in a secure state following a network or generator contingency (e.g. an unexpected failure of a critical transmission element). The System Security provisions in Chapter 4 of the Code provide the basis for this. These constraints are currently set by TNSPs in off-line studies that involve some technical complexity as well as some judgements about risk trade-offs. They are then used by NEMMCO in the SPD. In this context we note the following:

- The presence of active and binding constraints in the SPD other than those that reflect physical laws have an impact on the value of trade that can occur over the network and therefore require justification to Market Participants.
- NCAS is used by NEMMCO to influence the extent to which these constraints bind. Thus NEMMCO's activities in the procurement and dispatch of NCAS have a direct influence not only on the cost of NCAS but on energy market outcomes as well.
- The management of generic constraints in the NEM will therefore be an important part of the current brief.

Disparities between pricing and dispatch

Consistency between pricing and dispatch is a Code market design principle (Clause 3.1.4) and has also been translated to a principle guiding this project (Framework principle (iv) (a)). In essence, the principle reflects the requirement for markets that the participants be *willing*. If participants are instructed by NEMMCO to act in conflict with what they said they were willing to do in their offers, this principle is violated. It is noteworthy that the NEM has currently implemented has a number of examples where this principle is violated. As these examples are closely related to the operations of ancillary services, they are noted here and considered in more detail later in the report.

- Half-hour pricing.

  While prices are calculated each 5-minute and the associated dispatch is consistent with it, the process of averaging these prices over the half hour for settlement purposes violates this principle. The reason is that a Market Participant may be instructed to do something on the basis of a 5-minute price while the price she receives is less, because of averaging. This anomaly has been recognised and was considered by the ACCC in its determination on the Code, but accepted as at it stood. It is more significant in the context of possible ancillary service markets, and will need to be addressed as part of this project for that reason. NEMMCO's Pricing and Dispatch Reference Group is also addressing this issue.

- No price adjustment if constrained off by the network.

  If an intra-regional network constraint requires a generator to be reduced in output relative to what it would have been prepared to do at the regional price, the regional price is still paid for the constrained output. Given that the generator has been constrained off, this violates the consistency rule in favour of the generator. On the other hand, if a generator receives an instruction to operate at a level different from the market outcome for other reasons, (including to provide ancillary services) compensation is payable. Sometimes the boundary between these two reasons is unclear.

- Spot pricing and the demand-side.

  The energy spot market operates with two classes of energy producing and consuming participants, or at least plant owned by them; those that are *dispatchable* and those that are *non-dispatchable*. The Code is written so that only the offer prices of dispatchable plant (mostly generators) can set the energy spot price. Of course, plant and loads of any size can influence price outcomes indirectly by changing volume. But if non-dispatchable loads do this, the price could oscillate between a price at which they are prepared to consume and a price at which they are not prepared to consume. This possibility of an unstable outcome is greatest when supply is constrained and prices are high. While this is not formally a dispatch issue, it is a logical and probably practical flaw in the market that is likely to be inhibiting the development of the demand-side and it should be addressed. One possible solution that emerges from this project is a spot energy deviations price that willing participants could submit to. Such pricing could help to ameliorate the rather large price "holes" and unstable price patterns that appear from time to time.

2.2.2 The Ancillary Service ITT and its Outcome

A new tender process was introduced by NEMMCO for the procurement of ancillary services under the National Electricity Market (the "ITT"). This was held in February 1998 for the provision of services from the start of the National Electricity Market (in December 1998) until 31 December 1999 (now 30 June 1999). Before outlining the way ancillary services are currently organised, we briefly summarise written comment on the process that have been provided both by NEMMCO and Snowy Hydro representing the views of generators. Also summarised are some of key concerns that have been expressed by retailers.

All parties involved agree the initial ancillary service procurement process was drawn out and tortured. It suffered to some extent from the novelty of the process on all sides and shortcomings that arose from errors made under short deadlines and a severe underestimate by NEMMCO of the resources required to complete the task. However, as NEMMCO has pointed out, further tender rounds following the same approach may not lead to a much more satisfactory outcome[11]. Some of NEMMCO's key points are, in brief:

- There are fundamental difficulties for NEMMCO in negotiating long term contracts with commercial operators. The essence of the problem is the lack of flexibility that NEMMCO has, or believes it has, in negotiating the contracts and the one-sidedness of the negotiations as perceived by the potential providers.

[11] A further tender round was in fact completed prior to July 1999 following the ACCC's extension of the current arrangements. NEMMCO advises that this process was less tortured than the initial one, although co-operation may be anticipating the changes foreshadowed from the current review.

- There are inconsistencies of various sorts in the current arrangements including:
  - some services such as governor control are difficult to control and are provided whether or not they are enabled and receive payment;
  - there are inconsistencies between 5-minute pricing and dispatch and settlement (of the same nature as described earlier for the energy market);
  - the notion that NEMMCO pays compensation outside an agreed pricing rule implies to some participants that the matter is negotiable with NEMMCO; and
  - there is inconsistent application of the Code obligations for the provision of governor control and reactive capability.
- There is sufficient of each type FCAS to provide adequate competition, but barely enough for the other services[12].
- There are problems with the Code which include:
  - various inconsistencies in what constitutes a secure power system and, in particular, differences between TNSP planning and NEMMCO operational obligations;
  - some vagueness and inconsistencies in the definition of obligations under the Code to provide certain services (e.g. reactive capability); and
  - inconsistencies between compensation to generators for network constraints and for ancillary services, when the distinction in practice is not sustainable.

NEMMCO then went on to recommend a number of changes, most of which are considered in this report.

Comments from Snowy Hydro reflecting generator concerns mirrored those of NEMMCO at many points, with some differences and additions. Apart from the errors in documentation and the tortured and one-sided negotiation process:

- The mandatory requirements under the Code as interpreted by NEMMCO are not consistent with the cost of provision of the service.
- Many of the commercial conditions including testing, liability and default are weighed against the provider.
- The algorithms for compensation are flawed.
- The definition of technical requirements was too restrictive and froze out some potential providers.

[12] Although this observation must be viewed in the context of the particular ITT process and the particular terms and commercial arrangements that were on offer. In particular, there is no reason to expect that the ITT process would have any attractions for the demand-side, a problem mirrored in the energy market. It should also be noted that the advance notice to providers was generally not sufficient to allow new resources to be offered.

- The definition of 6 second, 60 second and 5-minute services is arbitrary and performance potentially difficult to measure.

As noted elsewhere in this report, retailers have two primary concerns:

- The method of allocation of costs of providing ancillary services is currently unfair (under Schedule 9G of the Code) in that retailers are required to pay for services that they consider they do not cause (although their customers may be).
- The costs are passed on by NEMMCO as incurred. They are potentially volatile (largely because of the energy compensation payments), difficult to hedge and can have a major impact on retailer margins.

The conclusion to be drawn from this is that there is a lot to improve upon and there is a clear consensus for change. Some key areas for consideration in this report are:

- NEMMCO should be less involved in commercial negotiations.
- There is scope for shortening the bidding horizon for FCAS provision and thereby broadening participation.
- There is a need to review and clarify aspects of the Code including current mandatory provisions, security definitions and interfaces between NEMMCO, TNSPs and DNSPs.
- There is a need to re-consider the product definitions for ancillary service provision, and especially so if more market-oriented arrangements are to be established.

Most of these possibilities are reflected in the terms of reference for this brief.

2.2.3 Current Ancillary Service Operations

This outline of current arrangements for ancillary services in the NEM concludes with a brief overview of current operational and settlement arrangements. Operational arrangements are summarised more fully in Appendix 1, which in turn is a summary largely drawn from (6), which is available from the NEMMCO Website.

At present procurement of ancillary services proceeds with the following priorities:

- Utilisation of resources available to NEMMCO under the mandatory provisions of the Code and connection agreements.
- Competitive tenders where there are competing providers (who, to date, with the exception of interruptible loads, have been energy suppliers in the energy market).
- Negotiated contracts where the potential provider(s) of the service have market power, either generally or because of spatial considerations.
- Direction, if necessary and as a last resort.

The dispatch process essentially proceeds as follows:

- NEMMCO determines the quantity of each service it requires with reference to standing assessments in some case:
- It then dispatches each service to meet its assessed requirements at least cost, using the resources it has available to it under long term contracts:
    - those that are freely available under mandatory provisions are dispatched ahead of those that require additional payment;:
    - for some FCAS services the dispatch is determined by the logic built into the SPD;
    - other services are dispatched in order of enablement price; and
    - if these resources are considered insufficient, NEMMCO will constrain units off the energy market to provide the service, and pay the corresponding compensation (where this is not already provided for e.g. under the FCAS arrangements).

Payment by NEMMCO to providers of ancillary services is split into *availability*, *enablement*, *use* and *compensation* components. Not all components apply in a specific case. Payment for *availability* is intended to cover ongoing fixed costs. Payment for *enablement* covers the cost of making a resource ready for use. It is sometimes a substitute for a usage payment if measurement is impractical. Payment for *use* covers additional costs that may be incurred when the resource is actually used. *Compensation* covers the assessed opportunity cost of providing the service when it might otherwise have been used profitability for energy or other production. Dispatch of FCAS for enablement is generally achieved through facilities coded into the energy market SPD logic, with some exceptions. However, for this and other ancillary services, all the resources used are under long term contracts, and they are enabled and used according to long-term offer prices written into those contracts.

2.3 Ancillary Service Arrangements Elsewhere

2.3.1 Overview

Ancillary services are managed in various ways in all of the overseas electricity markets. However these arrangements are generally similar to the current NEM arrangements, and past arrangements in VicPool and the NSW SEM.

The **UK market** features an uplift payment on the pool price that was used to recover the cost of ancillary service (and other costs), with the required quantities being specified by the National Grid Company. The UK market rules have been under examination by the Office of Electricity Regulation (OFFER), and new Pool Rules are proposed. These new rules do not as yet offer any experience with ancillary services.

In the **New Zealand** market, ancillary service are specified by the transmission company Transpower. The reserves required for frequency control are bid on a daily basis, and are co-dispatched with the energy market.

The US is currently undergoing reform in many of its electricity regions. This is as a result of new rules set by the Federal Energy Regulatory Commission (FERC), which seek to create open access in transmission. These rules also cover the provision of ancillary services.

The US experience is examined in some detail in Appendix 5. This appendix outlines the applicable FERC rules, followed by the arrangements in California, where a new wholesale market has been in operation since March 1998. Key points are summarised below.

2.3.2 US Approach to Ancillary Services

FERC Rule 888 requires that the following **six ancillary services** must be included in an open access transmission tariff (the approximate Australian NEM equivalents as defined in the Ancillary Service Framework or elsewhere in the Code are shown in brackets):

(1) Scheduling, System Control and Dispatch Service
(paid for through pool fees in the NEM);

(2) Reactive Supply and Voltage Control from Generation Sources Service;
(part of the continuous and contingency voltage control services)

(3) Regulation and Frequency Response Service;
(small and large frequency deviation management services)

(4) Energy Imbalance Service;
(not applicable in the NEM centralised pool design)

(5) Operating Reserve - Spinning Reserve Service; and
(energy market top end and large deviation frequency management service)

(6) Operating Reserve - Supplemental Reserve Service.
(energy market top end)

The Rule requires that the Transmission Provider **must provide**, and the Transmission Customer **must purchase** from the Transmission Provider, the first **two** services, subject to conditions set out in the Rule.

The Transmission Provider **must offer** the remaining **four** services to the Transmission Customer serving load in the Transmission Provider's control area. The Transmission Customer that is serving load in the Transmission Provider's control area **must acquire** these four services from the Transmission Provider, or a third party, or self provide.

In the Australian context, a Transmission Provider would be a transmission NSP such as TransGrid, and a Transmission Customer would be a Distributor/Retailer such as EnergyAustralia or Integral Energy. Note that the Transmission Provider must provide reactive supply from its own assets, or by agreement with generators within its area, and that the Transmission Customers must purchase this reactive supply at the tariff price.

In general, the required quantities of ancillary services are centrally determined in accordance with “good utility practice”, and follow guidelines laid down by the National Electricity Reliability Council (NERC), and its regional subsidiaries.

The current arrangements for the management of ancillary service acquisition are similar in many respects to the arrangements for the Australian NEM. The required quantities are centrally determined by the ISO, in accordance with technical criteria, which in certain respects are very conservative. Reliability is being handled through ancillary service by the requirement for Replacement Capacity.

The Californian ancillary service arrangements are therefore causing much the same problems as in the NEM. In particular, the lack of adequate linkage between the energy market and the ancillary service market at times of high energy prices has resulted in shortages of offers for ancillary services.

As a result, the ISO has established an ancillary services Workgroup, which has the stated objective to:

"To improve operation of a market based procurement system for ancillary services.

By Market Based means:

- *Supply sufficiency*
- *Demand Elasticity*
- *Price transparency*
- *Lack of ISO intervention (i.e. operator, policy, price caps)"*

This Workgroup has been in operation since September 1998, and is addressing many of the issues currently being examined in the NEMMCO ancillary service review.

2.4 The Two-way Market Model

Ancillary services are currently provided through NEMMCO to address the *external effects* of electricity market trading, which would otherwise not ensure secure electricity system operation so that the market can function. There is another model for dealing with these external effects that offers future potential. That model will be outlined here, and compared with existing models in the following sub-Section.

The theory of externalities was addressed by the English economist AC Pigou in 1932. His analysis suggested the now widely known and implemented "polluter pays" principle, whereby the cost of market externalities is corrected by imposing a tax on the causers of the externality. This principle has so far not been applied to ancillary services in the NEM but was presumably the model the ACCC had in mind when making the determination that instigated the current ancillary service review.

Pigou's analysis was re-visited by the American economist Ronald H. Coase in 1960. Coase showed that if property rights are clearly allocated, if parties can negotiate costlessly and there is perfect information (i.e. along the lines of the standard assumptions for a competitive market), then efficient outcomes result no matter how the law assigns responsibility for damages. In practice these idealised conditions are never realised. But Coase's analysis does suggest policy options broader than those proposed by Pigou, even though application requires analysis of each circumstance. Specifically, there may be opportunities to trade a well-defined product even where that product might initially be perceived as an externality.

Emissions trading is an example of this approach. Sulphur emissions trading is established in the US and greenhouse gas emissions trading is mooted. To establish such a regime, a target or *standard* for the emissions must be set, probably as an upper limit on the total quantum of emissions each year. Rights to emit are then established as well as regulatory and monitoring arrangements to enforce them. After an initial allocation of rights by a public regulator, all the parties may trade them for a price determined by the forces of supply and demand. Trading parties include those who tend to increase emissions and those who tend to decrease emissions that affect the achievement of the standard. Theory suggests that trading parties will then act to achieve the standard. It is noteworthy that a regulatory process is required at several points; first to establish the standard to be achieved; second, to ensure the necessary information flows; third, to define, assign and secure property rights in the products that affect the achievement of the standard; and, finally, to provide oversight and take remedial measures should the trading system not work adequately.

There are prospects of applying similar concepts to FCAS and some NCAS in the long term. The approach is summarised in the next sub-section and applied in the Sections that follow.

2.5 Assessment of Models for Ancillary Service Provision

2.5.1 Three models

The review of this section highlights three broad models for dealing with ancillary services in the context of an electricity market. These are:

- ancillary service provision by a market/system operator by *centralised procurement* from Market Participants (e.g. the current NEM);
- ancillary service provision by Market Participants through an *obligation to purchase* from registered sources (e.g. US FERC rules as implemented in California); and
- centrally determined security standards maintained through *competitive two-way markets.*

2.5.2 The Centralised Procurement Model

In ***outline***, this model is:

- A central system/market operator is accountable for providing a "required" quantum of ancillary services o meet a defined standard of system security.
- That capability may be acquired in a number of ways, either through a tender process for long term contracts (recent practice in the NEM) or in a shorter-term one-sided procurement market (an option for FCAS in the near future).
- Central dispatch of ancillary services approximating a least cost outcome.

- Payment could be based on bid prices (e.g. availability, enablement, use, compensation) or a common clearing price.

Advantages of this model in the context of the NEM are:

- Being close to status quo might imply relatively quick implementation of improvements;
- Direct control by the accountable body (NEMMCO) – more apparent than real.
- Relatively easily understood by participants.

The ***disadvantages*** of this model are:

- The quantum of ancillary service to be procured is not always fully tested against "willingness to pay" leading to risk of over-supply, although this could improve if "polluter pays" principles were more fully applied[13];
- Procurement based on assessed "need" tends to increases the market power of suppliers and reduce the scope for adequate competition in the supply market as a result;
- Suppliers must negotiate with single buyer and there is little incentive for a buyer to be flexible or innovative.
- It is unsympathetic to an eventual move to entrepreneurial networks or network elements.

Our **assessment** of the *Centralised Procurement Model* in the context of the NEM is:

- While few consider it ideal, it is working now and could be significantly improved relatively quickly.
- Such improvements could provide a viable transition path to a more market-oriented approach and in some cases might be a long-term solution.
- The lack of "willingness to pay" test is likely to lead to ongoing inefficiencies, including over-supply and restricted sourcing options.
- It maintains the problem of passing on potentially volatile ancillary service costs to those parties assessed as having the obligation to pay.
- It is not compatible with the concept of entrepreneurial networks or network elements[14].

2.5.3 The Obligation to Purchase Model

This model is currently applied in the US as outlined earlier. It maximises the opportunities for the *self-provision of ancillary services*. In ***outline***:

[13] Payment in some cases is based in load profile characteristics that can provide some well-directed incentives if carefully structured.

[14] Network entrepreneurs should presumably organise their own ancillary services according to security guidelines managed through NEMMCO. NEMMCO would still dispatch the services where appropriate.

- There is an obligation on each Load Serving Entity (LSE, to use the US term) to *purchase a quantum of each service* based on the characteristics of the LSE's served load.
- Broadly the, quantum may be self-provided, contracted out to others, or provided through the central operator.
- Depending on the service, the facility may be self-dispatched or centrally dispatched.
- The central operator has no commercial interest in the procurement process.

Advantages of this model in the context of the NEM are:

- There is no necessary involvement by the central operator in commercial negotiations and financial transactions (except to apply penalties for non-performance).
- Despite physical rather than bid-based dispatch and the lack of formal procedures for co-dispatching with energy, opportunities for external trade suggest reasonable supply efficiency should be achieved, at least in the US context of large market areas.
- The self-dispatch of some ancillary services is sympathetic with energy self-dispatch logic applied in many US markets.

The ***disadvantages*** of this model are:

- The quantum of each ancillary service to be provided remains centrally determined, which does not test willingness to pay and therefore imposes a risk of over-supply.
- If applied to the NEM, short-term co-ordination between centralised NEM energy dispatch and decentralised ancillary service dispatch could be difficult for both NEMMCO and providers.
- It may be less sympathetic to small systems with a strong open access philosophy, as small new entrants might find negotiations difficult with large "marketers" who typically co-ordinate service provision instead of the central operator.

Our **assessment** of the *Obligation to Purchase* in the context of the NEM is:

- Some elements such as the decentralised procurement of ancillary services, given the difficulties with the ITT, are attractive, and might help resolve the problem of passing on volatile costs to those assessed as having the obligation to pay.
- There is a philosophical and operational gulf between some decentralised ancillary service dispatch and centralised energy dispatch that may be hard to bridge.
- It does not solve problem of how to test for willingness to pay.

2.5.4 The Two-way Market Model

In ***outline***, this model is:

- Define through some rigorous public process the standard to be achieved; this will require an economic, social and technical analysis that will usually include assessments of risk.
- Define and provide the necessary information requirements.
- Define a tradeable product whose production and consumption affect the achievement of the standard.
- Implement and enforce arrangements that allow this product to be traded between the interested parties.
- Define and provide arrangements for regulatory oversight and intervene should the standard be breached.

Advantages of this model in the context of the NEM are:

- Where it can be applied it would remove NEMMCO from commercial negotiations.
- It provides mechanism for testing and acting upon willingness to pay, reduces supplier market power and enhances prospects for a competitive market.
- It is an incremental development from current energy spot SPD logic (see later Sections).
- It is sympathetic to a later move to nodal pricing and entrepreneurial network activity.

The ***disadvantages*** of this model are:

- It may be perceived to add to the complexity of the NEM.
- Transaction costs may not be justified in some cases in the context of likely NEM ancillary service costs of around $100 million per year.
- Not tested elsewhere, although elements have been mooted in the US (see later Sections).

Our ***assessment*** of the *Two-way Market Model* in the context of the NEM is:

- It has the important advantage removing NEMMCO from direct commercial negotiations.
- It provides a mechanism that can reflect the *value of the service* and therefore tests the willingness to pay for the service. This should drive down the demand for each service together with the associated costs (see later).
- It supports open access and equality of treatment of both dispatchable and, in some cases non-dispatchable options (see later).
- It defines the parties and counter-parties who could manage the mutual risks in ancillary service provision and consumption through hedging arrangements (see later).

2.5.5 Comparative Assessment of Models of Ancillary Service Provision

The *Central Procurement Model* as applied now in the NEM could, with further development and refinement, be made into a workable arrangement for ancillary service provision based on the standard "polluter pays" model for dealing with market externalities. This is a worthwhile goal for early implementation and is not necessarily inconsistent with more radical approaches that might be considered for longer-term implementation after more investigation and experience. Major drawbacks are the lack of a test for willingness to pay, the ongoing involvement of NEMMCO in commercial negotiations and, potentially, the ongoing problem of NEMMCO passing on volatile costs to the parties assessed as having the obligation to pay.

The US approach as described in the *Obligation to Purchase Model* has two key advantages; it removes the central operator from commercial negotiations and, as an important corollary, passes a physical rather than a monetary obligation onto those assessed as having the obligation to pay. It does this by taking a more sophisticated approach to defining the rights and obligations of participants than does the current NEM. In that sense it can be seen as one implementation of the Coasian approach to externalities. On the other hand, the concept of self-dispatch of the services does not sit easily with central energy dispatch in the Australian NEM, but self-procurement (generally the US model) does not *necessarily* imply self-dispatch. Adopting some elements of the US self-procurement approach might reduce some of the difficulties associated with the current central procurement philosophy of the NEM, particularly the high degree of NEMMCO involvement in commercial negotiations and the risks posed to those who are obliged to pay for them. This matter should be considered in the "who pays and how much" stage of this brief.

Both the previous models suffer from the disadvantage that willingness to pay is not adequately tested. Some attempt could be made to do so when applying the polluter pays principle to the payment for these services, but such logic can be crude in its discrimination in time and between the members of the class of participants that might be deemed liable in each case. This could be tackled by more finely discriminating the obligation to pay in time and between participants. However, a better approach could be to establish two way markets in the service wherever practical. These markets would require a careful definition of rights and obligations and in this respect similar to the US Obligation to Purchase Model. However, a key difference is that a two -way market would define the *standard to be achieved* in terms of risk measures such as frequency deviations. *With products, rights and obligations appropriately defined, the market can be left to determine the best way to meet the standard. This is a fundamental difference with the Obligation to Purchase model where the quantum of service required is assumed given and only the means of providing it is open to negotiation between providers and those obliged to pay.*

In summary, our broad approach will be:

- Recognise the scope for substantial improvement to the existing arrangements and pursue them for early implementation, especially where they are likely to be compatible with later developments.

- Consider the scope for applying some elements of the US Obligation to Purchase Model during the “who pays and how much” stage of this project.
- Consider two-way market options for the longer term, to be applied in the more prospective areas in the first instance, and in a way that allows operation in parallel, where appropriate, of the older arrangements.

3 Frequency Control Ancillary Services

3.1 Overview

In Section 3 we consider FCAS in more detail, noting the close relationship in the management of both small and large frequency deviations, which are the two services defined in this group. NEMMCO's current obligations in this respect are addressed in Chapter 4 (Clause 4.4.2) of the Code, the relevant parts of which are reproduced below.

To assist in the effective control of power system frequency by NEMMCO the following provisions apply:

(a) The power to control and direct the output of both scheduled generating units and scheduled loads is given to NEMMCO pursuant to clause 4.9;

(b) Each Generator must ensure that all of its generating units have responsive speed governor systems in accordance with the requirements of schedule 5.2, so as to automatically share in changes in power system demand or loss of generation as it occurs through response to the resulting excursion in power system frequency;

(c) NEMMCO must use its reasonable endeavours to arrange to be available and specifically allocated to regulating duty such generating plant as NEMMCO considers appropriate which can be automatically controlled or directed by NEMMCO to ensure that all normal load variations do not result in frequency deviations outside the limitations specified in clause 4.2.2(a);

(d) NEMMCO must use its reasonable endeavours to procure ancillary services (via contractual arrangements associated with the availability, responsiveness and control of necessary contingency capacity reserve and the rapid unloading of generation) as may be reasonably necessary to cater for the impact on the power system frequency of potential power system disruptions ranging from the critical single credible contingency event to the most serious multiple contingency events;

(e) NEMMCO must use its reasonable endeavours to ensure that adequate facilities are available and are under the direction of NEMMCO to allow the managed recovery of the satisfactory operating state of the power system.

Noteworthy here is that while the responsibility to have governors is clearly mandated, the requirement to make them available to NEMMCO for use is not. In this section we will assume that this capability must be procured on some commercial basis. The question of mandatory provision should be addressed in the "who pays and how much" phase of the project.

3.2 Review of Framework Classification Matrix

3.2.1 Cause of the Requirement

The Framework lists the causes of small deviations (specifically, the requirement to manage these deviations) as demand variations, demand forecast error (5 minutes) and non-conforming scheduled participants. The causes of large deviations are listed as generation/ demand changes (planned and unplanned), and network contingencies that isolate generators.

The system pricing and dispatch (SPD) process is used to match estimated supply with estimated demand over each 5-minute interval, looking forward. In essence, deviations arise from unforeseen changes in the balance of power supply and demand within that 5-minute dispatch and pricing period. Differences between the SPD's modelled calculation of supply requirements and the supply actually required would also give rise to an adjustment that would appear within this service group. As noted earlier in Section 2, the incentives for plant to conform to dispatch instructions when load is changing rapidly is also diluted by the process of paying on the half-hourly average of five minute prices while dispatching on the basis of 5 minute prices.

Some of the causes of these deviations (especially the last two listed for small deviations) arise from the conventions of the energy market. Specifically, if the SPD operated over a half hourly interval (as did the state-based markets when first established), or if it were run a day ahead (as in England and Wales) there would be greater deviations and a greater need for this group of services, all else being equal. Conversely, a shorter interval for price setting and dispatch might result in a reduced call on these services or even the possibility of bringing some them into a short-term / spot energy deviations market that might be one way to organise FCAS in the future. The possibility of such a light on the hill will be explored later.

Finally, it must also be recognised that both energy producers and energy consumers cause frequency deviations to varying degrees, and energy producers and consumers can and do provide the services that correct those deviations. On the energy consumer side, most causers and potential providers will not be part of the dispatch process[15]. *It follows that an approach to FCAS provision and charging that relies exclusively on the energy market dispatch process is likely to exclude an important group of FCAS causers and providers, and thus not meet the requirement of technology neutrality provided for in the Framework Principles*. On the other hand, the need to demonstrate the provision of a capability will continue to act as a barrier to entry such time as until actual provision can be easily measured or assured.

[15] Unless a block of load explicitly submits a load reduction offer into the energy market it is regarded as "non-dispatchable" by NEMMCO. Such load is assumed to behave autonomously, and the role of the system operator is to meet that load following the rules and procedures established under the Code for the operation of the energy spot market. Thus while NEMMCO, when determining its FCAS requirement, accounts for the non-dispatchable load relief that occurs when frequency drops, the frequency response of this load does not at present enter into any of the arrangements relating to the provision of or charging for FCAS.

3.2.2 Driver for Quantity of Requirement

The quantity of the FCAS requirement in various categories, together with the efficiency of the arrangements in place to provide it, will determine its ultimate cost regardless of how it is paid for. For the small frequency deviation FCAS the Framework lists these as:

- maximum/minimum frequency following credible contingency;
- frequency deviation due to credible contingent event; and
- maximum acceptable time error;

For the large deviation FCAS:

- maximum/minimum frequency following credible contingency;
- Frequency deviation due to credible contingent event; and
- system inertia.

In essence, the quantity of the FCAS requirement (and therefore its cost) depends on the potential size of the frequency deviations from credible contingencies in relation to the tightness of the frequency standard that has been set. Speed of response is also a factor. Interim frequency standards and the conditions under which they apply have been set by the NECA Reliability Panel and are about to undergo a review[16]. They are summarised in Appendix C of the Framework and are reproduced below.

Table 3.1

Condition	**NSW/ACT/VIC/SA Interconnected Power Systems Frequency (Hz)**
Normal frequency band	49.9 to 50.1
Normal frequency excursion band	49.75 to 50.25
Frequency tolerance band	49.5 to 50.5
Frequency contingency band	49.0 to 51.0
Emergency frequency band	47.0 to 52.0

[16] A discussion paper on the topic was published by NECA on its Website as this report was being finalised. It suggests no change in standards for the next few years, but foreshadows possible changes after two years of experience with the NEM and the new ancillary service arrangements that would emerge from the current review.

The *frequency tolerance band* defines the limits to be achieved following a contingency. This may be achieved by on-line FCAS providers or it could mean that some load is shed under a specific large deviation management agreement.

The Framework classification matrix highlights the relationship between the small and large deviation FCAS: On the small deviation service:

"The need to maintain frequency *pre*-contingency (i.e. the driver for the small deviation service) is driven by the maximum/minimum acceptable *post* contingent frequency level. There is an interaction between the 'small deviation' requirement described here and the 'large deviation' requirement" and re-enforced in the matrix for the large deviation service:

"As the maximum/minimum post-contingent frequency value is dependent upon the pre-contingency frequency value, there is an interaction between the 'large deviation' requirement described here and the ' small deviation' requirement…"

Thus a justification for maintaining the relatively "tight" frequency standards for small deviation FCAS is to remain within the broader "frequency tolerance band" defined by the Reliability Panel's frequency standard to be met in the event of a contingency.

We review now the basis for the NEM frequency standards[17] and whether that basis might affect in any way the arrangements under which that requirement might be met. Because the conditions that determine the applicable band (i.e specific system events) are generally not under the control of the system operator, the standard does not and cannot prescribe outcomes except beyond the absolute upper and lower bounds of frequency defined in the table above. At these limits mandated load shedding by distributors or by generators will cut in automatically so that the system remains stable. Rather, the standard seems intended to drive an outcome that might be considered achievable and reasonable in the circumstances at the time. In fact, the bands, combined with actual system outcomes, can be thought of as describing an acceptable *statistical distribution* of frequency deviations[18].

With this background, the "driver for the quantity of the requirement" can be considered in terms of what makes the achieved frequency distribution acceptable. To consider this question, we note that the Framework defines ancillary services as those that provide for[19]:

- Power system security;
- Quality of supply (QoS); and

[17] This discussion focuses on the interconnected SE Australian system, as the current Queensland system standards are interim, pending completion of the planned interconnection.

[18] Seen in this way, a simplified index that might provide a more universal measure of FCAS performance is the *root means square* of the frequency error, or the *standard deviation* of that error, the target being zero by definition. Such a measure, or one closely related to it, might also need to make allowance for acceleration (inertia) effects as well as make a small adjustment for time error. The utility of such a measure is considered later in this Section.

[19] Section 5, first paragraph.

- Enhanced spot market trading benefits

that would not otherwise be provided by Market Participants on the basis of energy prices alone.

Frequency and time error are properties of electricity supply that apply across an interconnected AC system at any instant; that is, at any instant the levels of frequency and time error are constant at all points in the system. Consequently, *changes* in frequency and time error also occur in the same patterns at all points in the system[20].

Time error is a pure QoS issue with no impact on the secure or efficient operation of the system. There is a question as to how important it is even to consumers, but neglect of it would certainly cause some clocks to inconvenience their owners and there will be some industrial and commercial processes that assume that mains electricity can provide a good time measure. Meeting reasonable time error standards should, in normal circumstances at least, be neither difficult nor expensive using any reasonable approach. For this exercise we will assume time error control can be piggy-backed along with any approach to frequency control.

There is an important observation to be made about frequency control. Frequency deviations can affect both QoS and system security. There will be limits of frequency deviation that will be regarded as a necessary for system security and for a basic quality of supply. These limits are thus required for all participants and end-users, and hence to be taken as the basis for a regulated security standard. The idea is that, unless that standard is kept, there will be neither a secure basis for a market nor a merchantable product. Within this standard there will be lesser ranges of frequency deviation that will be differentially attractive to producers and consumers in the energy market. Because of equipment characteristics, some might prefer a smaller range of frequency deviations to a larger range. They might be prepared to pay a premium for that tighter standard i.e. for the higher quality product. Others might not; price elasticities could apply. But in any case if the tighter standard were adopted all would receive it. These issues and the way they might affect arrangements for the provision of ancillary services have not been addressed in previous discussions surrounding possible ancillary service markets and so there is a need to discuss the further here.

If system security is considered to be the dominant basis for frequency control (with time error control as a bonus), there would be no need to reference directly the QoS preferences of Market Participants and end users. The basis for setting the frequency standard would then be an economic trade-off between:

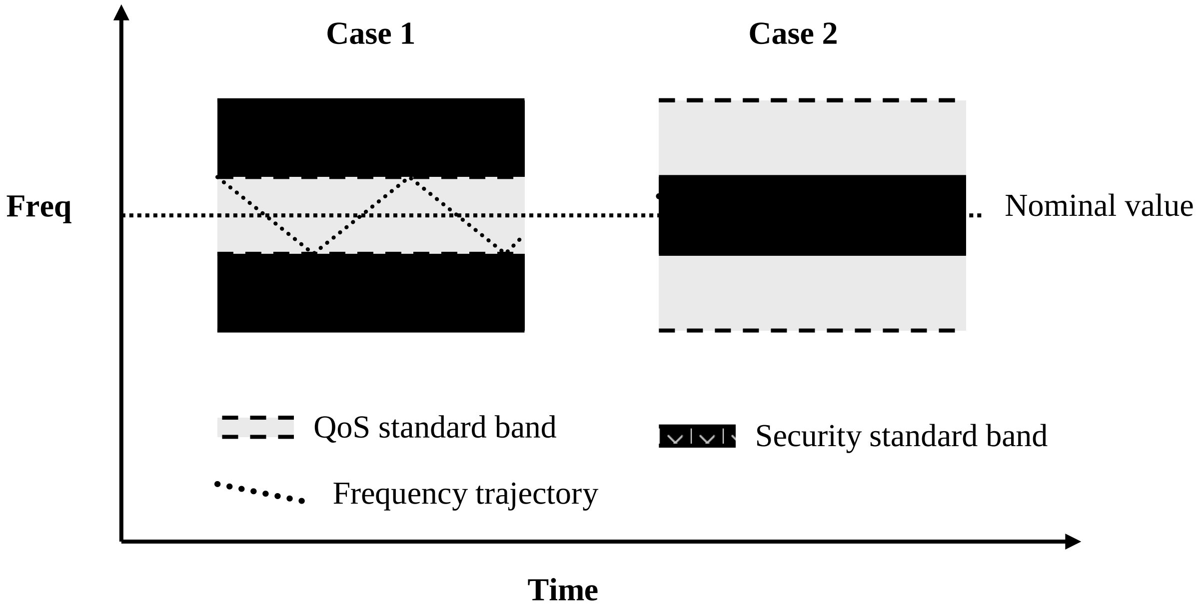
- The economic cost, using FCAS, of maintaining a particular small deviation frequency standard, and in particular, its "spread"; against

[20] There are in fact minute variations throughout such a system as system conditions change, but these do not accumulate and are irrelevant to the task at hand. Also, if a region of an AC system "breaks apart" for some reason there will be the possibility of a persistent time error difference on re-connection to the rest of the system.

- The assessed economic cost of varying the frequency standard. This is the cost associated with changes in the risk of incurring load shedding under an FCAS contract. The assessment should take account of mandated and currently uncompensated load shedding under automatic control, noting the over-riding need to maintain a stable system.

Of course, there are social and political considerations in such an approach but these are not new, and are a part of the Reliability Panel's considerations.

However, irrespective of the system security issues discussed above, it is likely that frequency deviations will affect at least to some degree the QoS seen by certain groups of customers or Market Participants. Consider the two situations sketched below.



In Case 1, the QoS requirement is shown to be more stringent than the security requirement according to some assessment. In this case, the FCAS would be arranged to keep the deviations within the QoS band; the security requirement would be met easily as a result. While it might be argued that those parties whose needs set the QoS (and tighter) requirement should pay to maintain it[21]; it could also be argued that some of the cost at least should be met by the presumably broader class of participants interested in maintaining system security. The priorities are reversed in Case 2 but the same issues arise.

We take the view in this brief that there is a presumption in favour of arrangements that tend towards efficiency. Such arrangements may or may not require an additional search for the parties most willing to pay, to the extent that there are residual costs to be met. *In other words, we believe the arrangement chosen should reflect the most efficient way to achieve the desired standard, irrespective of the basis for setting of that standard. This approach is consistent with the ACCC determinations on ancillary services as outlined earlier in this report.*

[21] This in turn raises "free rider" issues because the provision of these services has public good characteristics.

Finally, we consider the question as to whether any FCAS at all is required if the system is operating within a standard considered acceptable both in terms of QoS and security. Such an approach could (hypothetically, at least) lead to a frequency trajectory oscillating between the two extremes as shown in Case 1, where the control is only exerted at the time when the frequency is about to break the standard. The alternative is to exert more continuous control with a smoother outcome as shown in Case 2.

The approach of Case 1 (i.e. control only at the extremes of the standard) may be quite appropriate, and in fact preferred and practiced[22], to manage large deviations that are relatively infrequent. But for small deviations that approach may be technically more difficult to arrange (and perhaps more costly) than Case 2. Case 1 for small deviations, if interpreted literally, would require relatively large "pulses" of FCAS that could be difficult and expensive to organise on an ongoing basis[23]. However, small deviations do not in fact require sudden and urgent correction given that small and frequent random disturbances occur all the time in the system, in both directions. As noted earlier, it may be that some relaxation of the small deviation standard could allow some FCAS to be brought back into a spot energy deviations market with no significant impact on security and a very significant reduction in FCAS costs.

3.2.3 Technical Options for Meeting Requirement

For small deviation frequency management the Framework lists central frequency control (through AGC). For the future it lists demand management control and other options such as battery systems and DC inter-connector control. For large deviations the list includes the above and is extended by load (demand) shedding and rapid generator response options, network outage management and reducing the largest credible contingency.

In broad terms, then, the Framework envisages more extended demand-side participation in future. Load shedding (or fast-start generation embedded in a distribution network) capability has wide applicability that needs to be recognised and harnessed. It could be used to:

- provide a return to end users for helping to manage network contingencies *within* distribution areas e.g. shedding load for a relatively few hours each year to defer major investment in further distribution wires[24],as well as the applications that follow;

- manage spot market purchase costs through the controlled shedding of domestic hot water and other loads by retailers (or distributors on their behalf);

[22] Through the use of under-frequency relays to trip loads at pre-assigned frequency deviation levels.

[23] An analogy would be driving a car along a highway. Maintaining a smooth and steady line (requiring some skill but otherwise little effort) is likely to be safer and probably less costly in terms of wear and tear than letting the vehicle drift from one side of the lane to the other, with sudden and perhaps unsuccessful corrections at each side to avoid entering the neighbouring or oncoming lane. On the other hand, a perfect line is not required or possible and little is lost if minor deviations due to wind gusts or any other cause are not immediately corrected.

[24] The current proposal by Transgrid and Sydney Electricity concerning the augmentation of supply to the Sydney CBD is a possible example.

- manage the risks associated with high loads and high prices in the spot energy market;
- manage large frequency deviations as proposed in the Framework, with potential for managing small deviations as well;
- manage contingencies affecting voltage, as nominated in the Framework;
- provide stability control (high speed) as nominated in the Framework;
- provide network loading control, as nominated in the Framework;
- enhance system restart capability, as discussed later in this report; and
- generally, allow the some network constraints to be relaxed following a more detailed assessment of their basis.

Not all these requirements are strictly identical. For example to be useful for some types of stability control, load shedding must be fast-acting and directly controlled by the system operator. Particularly important to note is that load shedding capability used to assist both the distribution network and transmission network operations can be often be shared. Good co-ordination between processes intended to meet retail/distribution and transmission system requirements is therefore important and should be addressed in the context of retail and distribution regulation. This affects jurisdictional responsibilities under the Code.

For managing large deviations, the Framework explicitly nominates an option of reducing the size of the largest credible contingency and therefore the requirement for the large deviation service. Not mentioned is a similar approach for small deviation management, perhaps because such options seem more difficult to identify. *Arrangements that explicitly support a trade-off between the benefits driving a requirement for an ancillary service and the costs of providing that service were explicitly supported by the ACCC in its determination and are given emphasis in the proposals set out in this report.*

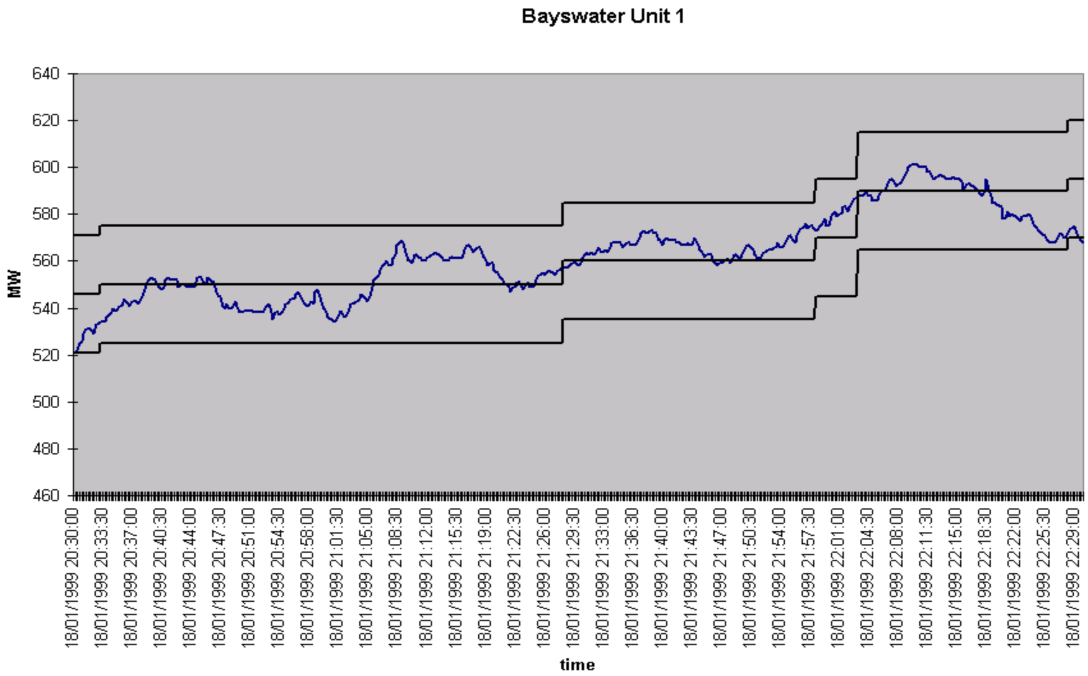
3.2.4 Measurements of Provision and Cause

The means of measuring the provision and cause of frequency management services are immediate *physical* measurements in the first instance, listed as frequency meters, System Control and Data Acquisition systems (SCADA) and local metering.

The frequency meter measures the key indicator driving he need for these services. Frequency measurement is at the centre of NEMMCO's system management function. But such meters could also be used throughout the system to drive decision-making and to help measure cause and provision of this service, because frequency is, for all practical purposes, the same throughout an interconnected AC system. SCADA is the technology used to measure the performance of and control participant plant from central points (NEMMCO's system control centres). However, the technology of local measurement of performance (MW and MWh, potentially at very short time intervals of the order of seconds) combined with local frequency meters opens up the possibility of relatively cheap and decentralised management of the causes and provision of FCAS on the demand-side.

Measuring FCAS provision and causes would be required to assign FCAS costs under a centralised purchase regime[25]. It is also relevant to a possible two-way market arrangement. The measurement method in the Framework can be understood with reference to Figure 3.1 below which shows a real sample of production from one unit over a period of 2 hours.

Figure 3.1: Example of Generator Unit Output, Set Points and Control Limits



The rapidly varying trace is the output of the unit as measured by the SCADA. The middle line is the set point (i.e. generation target at the end of the 5 minute period) determined by the energy market logic through the SPD module[26]. The upper and lower lines represent the upper and lower limits around the set point of the 5-minute raise/lower service that has been enabled for this unit. The AGC control range is about 15 MW up and 15 MW down, which provides only a part of the service that NEMMCO has contracted for. The generator output is driven by:

- the market base points that drive the unit toward the set point at the end of the 5 minute period[27];
- the 5-minute'regulation' FCAS raise/lower points, that adjust the output within the limiting bands according to the “regulation” logic, also implemented through AGC; and

[25] Analysis of specific options is outside the terms of this brief.

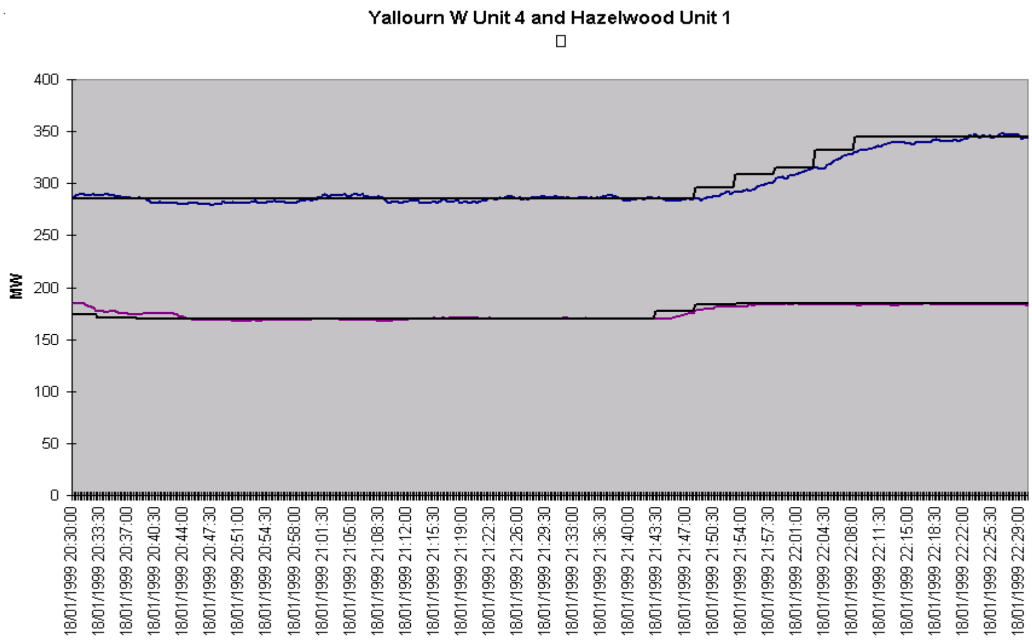
[26] The generator base point is determined via a ramped profile between the initial generating value at the start of the 5 minute period and the generation target or set point at the end of the 5 minute period determined via SPD.

[27] The generator base point profile defined between the initial and target/set point outputs depends on the response of the unit.

- any drift in output by the unit away from the assumed energy market profile.

The provision of the 5-minute raise/lower service (measured in MW) can be ascertained by a comparison of the actual unit output to that scheduled in the energy market[28]. The figure clearly shows that this value is controlled above and below the energy market-target, largely determined by the AGC's assessment of the power required at any time to drive the system towards power equilibrium. Real examples of units not under regulation control but driven by the AGC to energy market-determined set points is shown below in Figure 3.2. Control at the energy market base points is much tighter, although there is some minor drift as must be expected.

Figure 3.2: Example of Generator Unit Output Controlled to Energy Market Targets



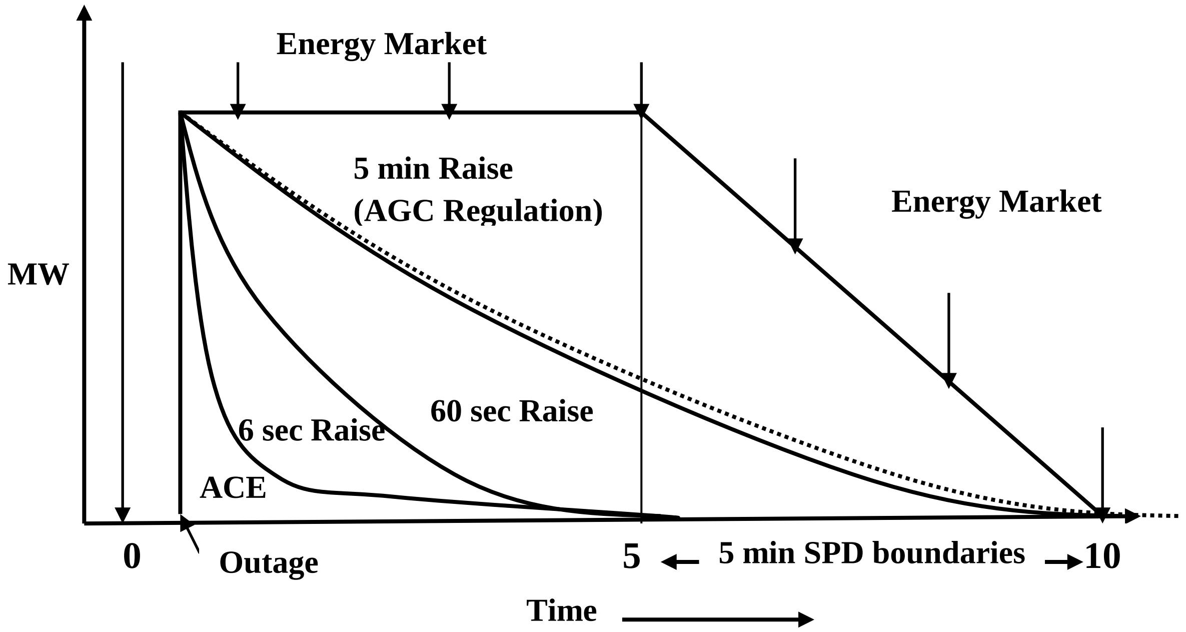
Such calculations could be made using energy market data. It would certainly be possible to measure in this way, with reasonable precision, total FCAS provision by generators and loads under contract to provide FCAS. It could also be used to measure how much a burden uncontracted generators place on the requirement for FCAS. Using statistical techniques the FCAS burden arising from any persistent bias in NEMMCO's load projections might also be determined, as suggested in the Framework.

To illustrate the outcome of this process, Figure 3.3 below shows an indicative response of the various classes of ancillary service, as currently defined, to a large contingency caused by

[28] This conclusion would be more difficult to draw if more than one FCAS service were simultaneously enabled; however the total FCAS provided could still be inferred. Also, an allowance should be made for the fact that the unit is "ramped" from one energy market set point target to the next.

a large generator outage. Note that a component for "lost" load as determined by the inertia and frequency response of the system after a large contingency is also included[29].

Figure 3.3: Indicative Response of FCAS Classes to a Large Generator Outage



The figure illustrates how the various services interact to keep the system stable until the energy market "catches up" after a disturbance. The response sequence is:

- Immediately after the outage the system decelerates and frequency drops, reflecting the power deficit as measured by a step change to the "Area Control Error (ACE)[30]".
- Fast response equipment arrests the deceleration (e.g. governors under the current "6 Sec Raise" FCAS contract[31] but this level of response cannot be sustained.
- The fast-acting FCAS response is replaced with slower response options (e,g, hydro under a 60 second raise FCAS contract) capable of maintaining output for a longer period.
- Generators under AGC control (under a 5 minute raise contract) then begin to take over the faster acting FCAS by ramping up (and ramping the other plant down).
- At the end of the 5-minute dispatch period, the SPD moves the power deficiency to the energy market and ramps up energy market plant so they can met the entire requirement

[29] This component is closely related to the Area Control Error (ACE) as used in AGC and will be referred to in later discussion.

[30] The ACE as implemented in NEMMCO's AGC and as normally interpreted excludes an inertia term as it is intended to be used over periods where inertia effects are insignificant.

[31] Although governors not under contract may also respond.

without ongoing FCAS. The effect of this is to gradually bring FCAS plants back to their energy market set points (i.e where they provide no energy under FCAS unless the system is further disturbed), until energy market plants have fully replaced the large unit that went off-line.

At present, the SPD process responds only at each 5-minute dispatch period. This artifice increases the FCAS burden, especially the 5 minute Raise/Lower service as currently defined. The Figure as drawn suggests that the 5-minute Raise/Lower (AGC Regulation) component could be reduced if the bid-based energy suppliers could respond to the contingency immediately instead of waiting for up to 5 minutes. A possible more rapid MW response, with resulting implications for changes in energy prices, is indicated by the dotted line. Note that the slope of the energy market response line is determined by unit ramp rate limits but the market units would still be able to replace the AGC regulation in the case drawn. This possibility warrants further consideration.

The approach to measuring FCAS provision and cause described above and outlined in the Framework would not detect or measure the cause or provision of FCAS by *individual non-dispatchable loads*[32], because such loads do not have targets calculated by the SPD process. NEMMCO projects only *regional* loads. This current orientation away from non-dispatchable plant is important to note. Customers already provide significant load relief when frequency drops, and this useful response could almost certainly be enhanced over time, imposing a lower burden on contracted FCAS, if such sensitivity could be rewarded under a suitable market arrangement for FCAS. The demand-side is also likely to be a much cheaper source of FCAS when energy prices are high and dedicated energy-producing plant must be backed off to provide the service. In any case, technology neutrality is a principle of the Framework and would not be fully met if this were to be the sole approach to FCAS measurement.

There may be other approaches to measuring or estimating FCAS cause and provision that do not depend so strongly on the dispatch logic and which may be useful for pricing the service. Such a possibility will be explored later.

3.2.5 Geographical Considerations and Potential for Competition

The Framework notes there are no significant spatial limitations associated with the provision of FCAS, both for small and large deviations. For large deviations, the network single contingency standard allows load shedding or other options to meet this requirement to be located anywhere in principle, given that action can be taken to correct any potential network security violations after a contingency has occurred[33]. NEMMCO advises that a high level of competition in the provision of this group of services was confirmed in the last tender round.

[32] As measured at points of distribution system off-take from the transmission system, in the first instance.

[33] This flexibility arises form the current "n-1" network planning criterion that allows the network to withstand any single contingency. It should be noted, however, that flexibility to this degree may not persist indefinitely as current network security criteria come under review.

Section 2 summarised the various market models that could be employed to facilitate the provision of ancillary services, and FCAS in particular. The approach described in the following sub-sections would seek to improve the current single buyer arrangements and then work towards a broader based arrangement the brings both providers and causers into a two-sided market arrangement. In overview:

- For the shorter term, there are possibilities to improve the effectiveness of competition in the centralised procurement and dispatch process for FCAS *enablement*. This could be supplemented in some circumstances with implementation of some "polluter pays" principles, in order to help contain the requirement for these services[34].
- For the light on the hill, we envisage a two-way market for FCAS *use* for the management of small frequency deviations and to assist in the management of large frequency deviations. For the management of large frequency deviations such a two-way market may not be sufficient We therefore propose that a centralised procurement process continue for that service, either integrated with the proposed spot enablement markets or contracted longer-term to the extent necessary.

3.3 Options to Improve the Current Centralised Procurement Process

The current procurement and dispatch and pricing arrangements have been summarised in Section 2. In essence they involve:

- categorisation of FCAS services for procurement, dispatch and pricing purposes (e.g. the 6 Second Raise and Lower Services);
- procurement of the NEMMCO-assessed "requirement" each through a long term contract tender process;
- payments under the contract to be based on four payment categories:
  - *Availability*, a fixed payment in consideration of maintaining a facility ready for service when called upon, payable regularly after sign-up;
  - *Enablement*, a payment in consideration of the quantity of capability made ready for use in the dispatch process;
  - *Use*, a payment for some services (specifically, load shedding) in consideration of the actual use of the service - such payments does not apply to some technologies such as governors;
  - *Opportunity*; compensation in consideration of the assessed opportunity costs of backing off energy-producing units from their position in the energy market to provide the service;

[34] This approach is intended to improve efficiency, not just to allocate costs. Coat allocation is beyond the strict terms of this brief, but is implicit in the concept of a two-way market process.

- dispatch at spot time based on enablement prices, some of which are co-optimised in the existing facilities of the SPD to the extent possible, with the reminder dispatched manually but in enablement price order;
- settlement based on the bid process and actual enablement and use, as well as opportunity payments based on a "what if" methodology; and
- FCAS costs passed on to NEM Customers who are loads, as incurred in each settlement period.

The essence of this approach is that contract prices are used in the dispatch and settlement processes. As argued earlier, the scope for participation is limited by the process itself, which particularly discriminates against non-dispatchable provision. Areas for improvement are considered below.

3.3.1 Spot Market in FCAS Enablement

This possibility was particularly noted by the ACCC in its determination. Basing dispatch and settlement on long-term contract prices as practiced at present requires providers to place a significant premium on uncertainty. This is especially so since FCAS provision typically involves joint production with electrical energy or with some other commercial output in the case of load interruptibility. Generators, for example, will need to take account of the possibility that they might be backed off in the dispatch and compensated on the basis of their bid prices. They will be indifferent to this only if their bid prices are set at their short run costs. This is unlikely to be the case for generators, especially at times of tight supply when prices are high and backing off to provide FCAS seems most likely to occur. But it is also the case for load interruptibility, as the opportunity cost of lost production will depend, typically but not always, on the situation at the time[35]. A second major problem with the long term contract approach is that there are likely to be fewer parties willing to commit themselves than would be willing in a much shorter-term arrangement with clearly defined participation and pricing rules.

Given these shortcomings, an alternative approach would:

- Remove the requirement for NEMMCO to contract with FCAS providers long-term;
- Support a daily bidding process in the defined FCAS products (see later discussion), running in parallel with and operating similarly to the energy spot market;
- Dispatch the offered plant for enablement using the SPD co-dispatch logic for FCAS as is generally done now;
- Replace the current bid-based settlement arrangements with logic based on a common clearing price for each FCAS product in each trading interval, as discussed below.

[35] This observation does not necessarily imply that a short-term market in load interruptibility is necessarily desirable or practical, as other considerations will apply in reaching such a conclusion.

A number of implementation issues will need to be resolved:

- *Number of bid bands*: This could be 10 as in the energy market or reduced in number to simplify bidding. The trade-off is between the IT issues and user convenience;
- *Cap on bids or clearing price outcomes*: Such a cap could limit risks but care would need to be taken least the rule freeze out providers in a market when energy prices are high. This will be discussed in the following sub-section;
- *IT requirements*: Moving to short term bidding by itself would appear to impose few or no additional requirements on the SPD logic already implemented to handle long-term contract bids. A range of other IT infrastructure enhancements would be necessary, for example to handle communication of data for the short time bidding process. These requirements would seem to be quite similar to energy bids and could use the same IT infrastructure[36];
- *NEMMCO accountability*: For the foreseeable future some form of longer-term registration process for providers is likely to be necessary to give NEMMCO the comfort (given its system security accountabilities) that the required FCAS capability is there. However the process could be just a registration of capability that could be held periodically or simply dealt within on application by a participant. If the total capability considered as necessary is not offered for registration despite the opportunity to bid in the spot FCAS market, NEMMCO could revert to a contract tender round.

3.3.2 A Common Clearing Price for some FCAS

Under current arrangements, FCAS providers are paid on the basis of their offer prices, with additional compensation based on the current market outcome should adjustment to their energy market dispatch be required to provide the service. On the other hand the SPD determines the energy and (some but not all) FCAS dispatch jointly, essentially on a global "benefit maximisation" basis[37].

There are problems with this approach under current arrangements, likely to be exacerbated if a short-term market in FCAS is implemented as we propose. Under the current arrangements,

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[36] It might be possible to clear the FCAS market outside the SPD logic, for example by promoting a market in tradeable rights to provide an FCAS service. There would be a question then of satisfying NEMMCO that the FCAS resource is actually available at the time of dispatch, but arrangements may be possible that provide such assurance. However, the Principles in the Framework require "Co-optimisation of the Ancillary Services and energy market where possible..." so the possibility of independent FCAS markets has not been pursued here. It should be noted that the case for co-optimisation of reactive capability with generator energy production may be much less compelling than for FCAS.

[37] This approach does not guarantee that FCAS payments are minimised, only that the global benefits to all participants are maximised, given the requirement for FCAS. This issue has been controversial in the context of NEMMCO's assessment of the benefits of regulated inter-connectors. In this report we assume that the dispatch logic built into the SPD is appropriate. It should be noted that Queensland currently dispatches FCAS outside the dispatch engine and explicitly attempts to minimise FCAS payments.

there are anomalies (as argued by some generators) that some services are provided by plant outside the contracted arrangements because some governors are always on-line and must operate. However, more modern equipment can in fact be tuned to avoid response within a wide and adjustable “dead band”. It could be argued that such providers could have made a better offer, so no further sympathy need be afforded.

However, the problem becomes much starker in a spot market where offers are made every day and there rapid learning by participants in terms of likely outcomes and the sensitivity of those outcomes to offer price. In these circumstances, there is a strong incentive to attempt to pitch offer prices at that just sufficient to get accepted - in other words, to attempt to guess the market price. This is reasonable in bilateral markets where there is scope for information discovery over a reasonably extended period, but can lead to unstable market outcomes in centralised “bid” markets such as the NEM as participants try to guess the market outcome without realistic opportunities to negotiate. There is a strong analogy with the energy spot market here. In the energy spot Market Participants are paid, and pay, for energy at a common clearing price[38] because this emulates in a stable way what would have been achieved had it been possible to reach negotiated positions on a well-informed basis. This proposition was accepted by the ACCC in its original determination on the NEM arrangements.

A common clearing price within each region for each defined FCAS product is implicit in the SPD market clearing logic in the same way as it is for regional energy prices. It is the shadow price of the FCAS requirement constraint specified for the FCAS product concerned[39]. Such a price would cover both bid prices and compensation prices for the FCAS offers accepted, and offers rejected would see that their offer price and compensation, taken together, would not have justified their acceptance[40]. Use of such a common clearing price would also deal with another anomaly of the current approach – namely, how to calculate compensation prices without ambiguity[41]. The common clearing price for each MW over one hour of service would have the following form for the “marginal” FCAS product provider.

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[38] Determined as the offer price of the most expensive offer accepted, although the price setting procedure is more subtle where a network is involved.

[39] This is the “supply price” for the service as defined in the SPD model documentation. While the supply price for a product can vary by region, NEMMCO defines these products as being able to be sourced from any region, so that the supply price for each product will be the same across all regions.

[40] These properties are implicit in the SPD logic but will need to be further demonstrated with mathematical proofs (based on the SPD mathematical specification), concrete examples and quantitative studies if general acceptance could be gained.

[41] At present, FCAS compensation payments are calculated according to a “what if” study that removes all of the FCAS requirement and determines what the dispatch would have been without FCAS. This is then used to compensate on the basis of the difference between market price and bid price (or agreed compensation price in the case of load shedding). One question is which market price: before or after? And another is: should each service be removed one at a time in the “:what if” studies or all together? Decisions on these points have been made, but the degree of arbitrariness is unsatisfying.

Common FCAS Clearing Price = FCAS Offer Price +
(Energy Market Clearing Price – Marginal Energy Market Offer Price)[42]

The last term in brackets provides for a compensation payment for FCAS and is only relevant if the marginal provider has been backed out of the energy market to provide the service[43]. Whether or not this is so, the clearing price would adequately remunerate the provider based on his FCAS and energy market offers, taking into account that FCAS and market energy are joint products. Sub-marginal providers receiving the common clearing price should also be adequately remunerated if they are enabled for the FCAS product based on their offer prices for it.

There is a question of a possible price cap either on FCAS offers or on each FCAS clearing price. Inspecting the components in the above price shows that, the FCAS clearing price could still be as high as 2*VoLL if the offer price is capped at VoLL. This can occur when the energy market price is also VoLL and the system needs this block of FCAS. This is an extreme but possible case. We suggest that the issue be reviewed more carefully during the implementation stage. The danger is that a cap on either bids or clearing price that is set too low (where low is less than 2*VoLL) *could* result in insufficient FCAS being enabled even though such plant might be available to the energy market.

The remaining question is whether a common clearing price, whatever its other appeal, might result in greater payments to generators and other providers than would otherwise be the case. This must be evaluated in terms of the increased competitiveness that a spot market in some FCAS is likely to deliver, the relative price stability offered by common clearing price logic, and the transition arrangements we propose. Some form of vesting arrangement to contain risks, phased out over, say, 12 months, should reduce problems due to lack of familiarity. We suggest that these be a questions addressed in the ”who pays and how much?” stage of the ASRG project, based on more quantitative studies than could be carried out in the timeframe of this project.

3.3.3 Product Definitions for FCAS Enablement

As outlined previously, FCAS is currently defined in terms of various products and these product definitions have been implemented in the current IT systems and contractual arrangements. There are different ways that some of these product distinctions could have been drawn. The current ones have technology-specific logic[44] that contradicts to some extent one of the ASRG principles that the arrangement be technology-neutral. However, it may be

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[42] In some cases there might be additional shadow prices reflecting additional constraints. For example, the SPD includes a governor model for the current 6-second raise service that includes such additional constraints.

[43] The current compensation payments are based on a calculation that assesses the change between the situation with ancillary service constraints and what would have occurred if ancillary service constraints had not been included. This calculation uses the clearing price with ancillary service constraints less the marginal bid price that would have been received with no ancillary service constraints.

[44] For example, the SPD implements specific governor models.

difficult to draw other boundaries without making similar assumptions. Some of the current problems with product definition and an alternative approach are discussed here.

The current definitions relate to the ability to raise or lower the MW injection to or off-take from the grid over time horizons of 6 and 60 seconds and 5 minutes. They are defined as *independent products:* i.e. it is possible for a provider to be enabled for the 6-second but not the 60-second service, and vice-versa. This distinction is driven not only by technical capability but also by the outcome of the dispatch process, currently driven by contract offer prices. Further, there is no clear distinction made between the ability to respond to small frequency deviations and the ability to respond to larger ones. In practice, the 6 and 60 second products are currently intended to deal with large deviations, and the 5-minute with small. The distinction is real in the sense that the large deviation service is much less frequently *used* and providers will either be off line or have their equipment tuned to be inactive during operation in the normal frequency band (e.g. governors on generators). In contrast, providers of the small frequency deviation service will normally be on-line and activated as the service is used continuously.

An alternative approach would define the ability to respond over time to a particular range of frequency excursions. The current NECA Reliability Panel frequency band categorisation provides some basis for doing this. Broadly, three main bands can be identified:

- normal bands;
- single contingency bands; and
- multi-contingency bands.

It would then be possible for providers to define and submit a potential response pattern over time to each of the corresponding frequency deviation episodes. The profile would be accepted in whole, in part or not at all over the full time domain of the nominated response. Responses to higher frequency excursion events could be additive or distinct. For example, a provider might be ready and able to make a larger response over the whole time profile, or a larger response earlier and less later. Another provider might not respond at all to small frequency deviations, but would respond to larger ones according to some nominated profile. NEMMCO would need to determine the aggregate profile of its required response for each frequency deviation band. By selecting some sample points along the required time profile, the optimisation logic of the SPD (suitably extended) could be used to select and enable a combination of offered profiles that meets the nominated needs in the best way[45].

While an implementation along these lines is certainly possible, the benefits at this stage are hard to quantify, for several reasons:

[45] This would be done with an objective similar to the existing benefit maximisation approach in the SPD. The FCAS MW requirement could be determined externally, as is current NEMMCO practice, or internal to the SPD model based on the assessed demands placed on the service. Some internal facilities are available in the current SPD but are not presently used.

- The approach represents a significant change from current practice and would require much more refinement and understanding before a final decision to proceed. This is a sufficient reason to rule it out for the shorter-term.
- With the anticipated inter-connection between the SE Australian system and Queensland, and with the implementation of an energy deviations market in FCAS as proposed later in this section, reliance on the FCAS enablement markets for small and even some large frequency deviation FCAS is likely to be diminished, to a degree that cannot be fully anticipated at present.
- While the approach outlined could be more technology-neutral than the current approach, it does not by itself address the need to involve non-dispatchable plant, including that on the demand-side.

On balance, we consider that the financial significance of the enablement markets in FCAS is likely to diminish over time, and most rapidly for the small frequency deviation service once an energy deviations market is introduced as we will recommend. Enablement payments are likely to be retained for the large deviation service. Therefore, our recommended approach will generally be to run with the existing product logic for the short term and over the transition, but to reconsider the need for a more refined definition for the longer term. Noting the broad frequency categories defined by the NECA Reliability Panel and described earlier in this section, the long-term approach could evolve along the following lines:

- For normal operations (small frequency deviations), the most important market mechanism will be the *energy deviations market*, to be described later in this section. This would be supported by a *spot market in small deviation FCAS enablement* that would be retained for security or in case of the small deviations market not deliver the full requirement.
- The energy deviations market would provide some support for large deviations (single contingencies), but most of the remaining requirement would be supported by *spot markets in large deviation FCAS enablement*. These would support 6 and 60 second and a dedicated 5 minute services (distinguished from the small deviation service). Later, and if considered necessary, these separate products could be linked as a single time-profile-based product category, as discussed in this sub-section.
- The approach to dealing with multi-contingencies is likely to remain long-term contracts or Code requirements actuated automatically with under and over-frequency relays. We do not see a role for a short-term / spot market in such services, although provision could be through a competitive tendering process or, preferably, by participants themselves should they be required to pay for such costs if they cause them. Approaches along these lines could be considered in the "who pays" phase of the current ancillary service project.

3.3.4 Conclusions on the Spot Markets for FCAS Enablement

Spot markets for FCAS enablement integrated with the energy spot market should be considered for FCAS services that are or could be continuously enabled to correct small and large deviations. This will involve a registration process and short-term bidding, essentially using the logic already available in the SPD. Payment should be based on a common clearing price obtained from the SPD solution, just as the energy market price in a region is determined. The approach to the possibility of mandatory provision should be dealt with in the ”who pays and how much” stage of the ASRG project. Some re-orientation of FCAS enablement product definitions might be desirable for the longer term, but we suggest this be considered in detail in the light of market development over the next few years.

3.4 Options for Implementing some Two-sided Arrangements

A step forward from the proposed changes to the process of central acquisition outlined above would be to attempt to allocate to the causers of the FCAS requirement the costs resulting from their behaviour. This would be done on the grounds of efficiency in the first instance, rather than as an exercise in cost recovery. More detailed consideration should be deferred for consideration under the topic of “who pays and how much”, which is strictly outside the scope of this brief. Nevertheless, we note some possibilities here.

We observe that identifying causers of small frequency deviations and attempting to charge them for the cost of their actions does present logistical problems. A possible approach is outlined in the following sub-section in the context of the light on the hill. However, for causers or potential causers of large deviations the problem of identification is less difficult. This suggests possible improvements to the current approach to the large deviation service.

In both this section and in Section 3.5 we describe arrangements that would support two-way trade or negotiations for the provision and demand for ancillary services. These and later proposed arrangements contain administered elements because they address system security issues that must be dealt with on a very short timeframe and to the satisfaction of the system operator NEMMCO, which holds the accountability for system security under the Code.

3.4.1 Charging Causers for Enablement

At present, the amount of large deviation service required is calculated as a fixed requirement on the basis of the largest credible contingency with an allowance for the relief provided by loads. Large contingencies requiring a “raise” FCAS service are clearly identifiable either as large generators or as specific network elements, and similarly for contingencies involving a “lower” service. It would be possible to link the demand for this service to its supply directly through the SPD logic as the causing parties are almost certainly market participants. Such an approach could provide a more market-driven approach to determining the quantity and price of the service. It would apply only to service *enablement* rather than its *use* in the event of a contingency. Detailed consideration of this option will be left to the “who pays” stage of the project.

3.4.2 Charging Causers for Use

If a large contingency occurs and the service is actually *used*, under current arrangements there will usually be a payment made to the provider for that use[46]. The causers of large deviations leading to FCAS service usage involving payment are usually relatively easy to identify from dispatch records, although there may be some uncertainty in particular cases[47]. It would therefore be possible to charge the causer directly for this cost with the intent of discouraging unwarranted use of this FCAS service. Again, some significant issues of principle and practicality arise. However, it may be that the energy deviations market proposed in the next sub0section will obviate the need for any additional use payments.

3.5 An Energy Deviations Market – a Light on the Hill

In this sub-section we outline an approach to small and some large frequency deviation FCAS that will require further investigation as to feasibility and further analysis and debate as to desirability. We use the term "energy deviations market" to apply to a two-way arrangement that involves the buying and selling of energy deviations relative to the energy spot market. The pricing mechanism that would support this we term real time energy pricing (or simply real time pricing or RTP). We use this term to describe a process that produces prices for energy deviations at intervals of *less than 5 minutes*, noting that the term has sometimes been applied to pricing in the spot market and to dispatch timeframes of half an hour and 5 minutes.

The concept of an energy deviations market is based on the very simple observation that the energy market standard trading interval of half an hour and the pricing and dispatch interval of 5 minutes are compromises. They are a trade-off between having useful price and volume discrimination and having to deal with the sheer weight of data that would arise should a shorter interval be used. This compromise leaves the task of balancing supply and demand within the 5 minutes as largely a technical matter to be dealt with by the system operator using various forms FCAS.

It may, however, be possible to price energy at much shorter time intervals, in a way that would match willing supply and willing demand closely enough to meet the NEM frequency standards. Before considering this proposition in more detail, we list some goals for such an approach, noting their compatibility with the Principles of the Framework, including the ACCC's determination. The arrangements should:

- directly achieve the following Framework principles, among others:
  - ❑ generally, the achievement of a competitive pricing outcome, subject to consideration by the ACCC;

[46] This is certainly the case if load is shed under current arrangements, but if the contingency is handled with on-line FCAS *only* then no additional use payments would be made.

[47] For example, a generator may fall off-line due to an internal problem a problem with the network or a system operational problem.

- compatibility between pricing and dispatch;
- ancillary services not systematically substituting for energy;
- equal treatment of available technologies, in that non-dispatchable load could provide FCAS, reducing FCAS dispatched by NEMMCO and promoting further competition;

- be fully compatible with existing technical controls, including AGC, that maintain system security, by providing the incentives for the standards to be achieved competitively;
- be largely compatible with existing half-hourly energy market pricing logic, although some changes would be necessary;
- be capable of cost-effective implementation by making maximum use of existing metering and communication facilities; and
- provide a commercial environment where financial risk can be managed in a manner largely consistent with existing risk management practices, and certainly more readily managed than a simple passthrough by NEMMCO of FCAS costs as they are incurred.

In the next sub-section we first consider current arrangements for pricing within the half-hour and a current settlement anomaly that should be addressed. We then outline the settlement logic and measurement issues before outlining an implementation of an energy deviations market closely integrated with NEMMCO's current use of Automatic Generation Control (AGC) for the regulation of system frequency.

3.5.1 Existing 5-minute Dispatch and Pricing

The current-5 minute dispatch and pricing process was outlined in Section 2. Despite the decision to have a half-hourly market interval, it was found convenient to shorten the dispatch interval to minimise the deviation between market outcomes and the actual dispatch requirement. Thus a dispatch calculation based on bids and the current status of the system is performed each 5-minutes, looking forward to the next 5 minutes. Each such calculation also produces 5-minute regional prices. At this level, pricing and dispatch are compatible. However, settlement is *not* performed in this way. Instead:

- Each half hourly price is calculated as a simple arithmetic average of the previous 6 five minute prices; and
- Settlement payments are made on the basis of metered half-hourly energy and the averaged half-hourly price.

Table 3.1 illustrates the out-workings of this logic for a generator operating over a half-hour period in the NEM when prices and loads are rising rapidly (e.g. mornings before 8 am). The generator is ramping up to help meet the load.

Table 3.1: Outworkings of the Dispatch Process for a Ramping Generator

Interval	$/MWh	MW	MWh	$	d$/MWh	dMW	dMWh	d$
1	20	0	0	0	-3	-24	-2	6
2	20	0	0	0	-3	-24	-2	6
3	21	0	0	0	-2	-24	-2	4
4	24	24	2	48	1	0	0	0
5	26	48	4	104	3	24	2	6
6	27	72	6	162	4	48	4	16
Av/Tot	**23**	**24**	**12**	**314**	**0**	**0**	**0**	**38**

		Pmt$	A$/MWh
Pmts$	**Total**	**314**	**26.17**
	Market	**276**	**23.00**
	Diff	**38**	**3.17**

Incremental offer price = $24/MWh
Market payment = 23 * 12 = $276

In this example, the rising sequence of 5-minute prices produces a simple average price of $23/MWh that, under the current NEM rules, becomes the half-hourly spot market price. Under the current SPD logic, the generator is ramped up (the table shows the increase from a starting base) from interval 4 as soon as the 5-minute price equals or exceeds the assumed incremental offer price of $24/MWh. But the generator is not paid that price for this increment of output; it is paid only the half-hourly market price of $23/MWh. In this sense the generator is not a willing party to this transaction, at least in terms of the offer made in his energy bid. The amounts involved are small in the example and usually are in fact. However, when system conditions are more volatile, when the demand for FCAS and associated payments are also likely to be more volatile, the amount of the shortfall could be significant. *The effect could be a lack of interest in fast response by generators that could increase the FCAS burden.*

The issue is not only relevant for generators but to loads, whose responsiveness to changes in frequency after a contingency, for example, are not recognised and rewarded.

While this feature of the current NEM logic may not be considered to be strictly within this brief, it is inconsistent with a key Framework principle (consistency between dispatch and pricing) and also inconsistent with the real time pricing logic described in this sub-section. This issue of "sub 30 minute energy deviations" is currently being discussed in the industry. It is considered a significant issue because it impacts the economic benefits of providing five-minute signals to participants who may respond to such signals including demand, fast acting generation and entrepreneurial interconnectors[48].

[48] *Options that have been raised to address this issue include the following:*

- *Changing to a 30 minute dispatch and settlement period and treating the mismatch between actual demand and forecast demand as an ancillary service;*
- *Allowing Market Participants the option of going to 5 minute metering and settling on a five minute basis;*

3.5.2 Settlement Logic using RTP in an Energy Deviations Market

Energy deviations market settlement logic for one measurement interval (say 4 seconds duration) for one unit would be based on the following formula:

Payment = Real Time Price * Energy Deviation

where

Energy Deviation = (Actual Power – Target Power from Energy Market) * Interval Duration

The RTP would be calculated form a formula based on frequency measurements that will need to be investigated.

The 5-minute SPD process in the energy market sets a profile of production for dispatchable plant based on NEMMCO forecasts of load. Energy deviations (i.e. power deviations multiplied by the interval duration) are calculated as the difference between these forecasts and scheduled operations and actual operations. This creates balanced settlement payments under idealised conditions:

- Actual electrical powers must balance over all physical participants in an idealised lossless system; it is the imbalance in mechanical powers that produce the frequency deviations.
- Target powers from the energy market would balance in an idealised system, as the SPD guarantees a balance at discrete 5 minute intervals and loads and generators are assumed to ramp linearly between these intervals.
- It follows the difference i.e. the deviations, must balance over all physical participants.

In a real implementation, system losses and metering errors would need to be accounted for, as they must be in the energy market. Further, if only a sub-set of physical participants is involved in the arrangement during a transition phase (because active participation has been deemed voluntary, for example), the settlement process will require an injection of funds that should logically come from those who are not directly participating. This is a matter that should be addressed in the "who pays" report.

Further implementation issues will be addressed elsewhere, but several things should be noted here.

- As a practical as well as a policy matter, the real time transactions would be performed by automatic processes and, at least initially, generally the same processes that NEMMCO uses to run the NEM system now.
- The energy deviations market settlement payments could be based on SCADA standard metering with suitable adjustment to correct any biases in measurement that may be

- *Treat the mismatch as an ancillary service or sub half-hour energy service and compensate Participants for the mismatch if they have 5-minute metering.*

detected from half-hourly metering. This is defendable because the payments would be relatively small.

- Because the proposed energy deviations market transactions are closely related to energy spot market transactions, it might reasonably be expected that viable energy deviations hedging products can be developed, perhaps very similar to current energy market hedges.

- As discussed later, participation in such arrangements could be voluntary during a transition period if market participants are concerned about their ability to manage such an arrangement. In such a case the settlements would not balance, so and residual costs would need to be allocated across non-participants as noted above.

3.5.3 Linking AGC Regulation more closely with Energy Market Dispatch

If the possibility of consistent pricing and dispatch at intervals of less than half an hour is recognised and accepted, there is a prospect of fine tuning the pricing and dispatch process. This would be done either to reduce the need to contract for FCAS, or at least to better support the energy deviations market just outlined. The essence of the proposal is to allow units operating in the energy market to respond more or less continuously to the supply requirements of the system if they can do so consistently within the ramping rate limits and offer prices they have made to the energy spot market. Such operation would not alter the distinction between the energy spot market and the ancillary services market but would change the boundary between them. This boundary issue will be discussed further later.

As described in Section 2, pricing and dispatch of the system is re-calculated every 5 minutes. The SPD logic performs a 5 minute load forecast, notes the current dispatch levels and calculates a dispatch pattern[49] and prices for the next 5 minutes that is expected to allow the system to remain in adequate power balance with minimal FCAS support. Under normal operating conditions, balancing within the 5 minutes is achieved mostly by adjusting the output of generators under an FCAS 5-minute raise/lower contract. The amount of the service required is determined externally[50].

The AGC provides the intelligence to drive this service. In essence, when it determines that more or less power is required, it ramps the bank of generating units “enabled” for the service up or down more or less in unison, according to “participation factors” calculated without reference to energy market offer prices[51]. Several factors could support such an approach:

- As a practical matter, the SPD re-optimisation IT workload becomes burdensome at intervals of less than 5 minutes.

[49] The dispatch is essentially a set of ramp rates that are calculated by the SPD and disseminated to participants (mostly generators) via the AGC. These rates stay constant over the 5 minutes unless a generator has an FCAS contract, in which case the AGC may make adjustments within the 5 minutes.

[50] And will change over the day, for example to meet additional control requirements in the morning when loads increase rapidly.

[51] Although these are taken into account to some extent in selection the enabled units.

- The combined ramping capability of a number of units may be required to match supply and demand within a period of less than 5 minutes[52].
- Generally, less than 5 minutes is too short a period to expect responses according to energy market price offers[53].

Setting aside the first point, we address the second by noting that a SPD optimised solution can be expected to have reasonable validity not only *at* the solution, but also at points *near* the solution. This is expressed in the various marginal analyses supported by the standard optimisation tool that the SPD uses. In practical terms, an SPD solution should produce not only the dispatched offer volumes but also an unambiguous *ranking* of offers, with those at one end of the ranking accepted, those at the other end not accepted, and the marginal offer or offers clearly identified[54]. While the possibilities needs further exploration, the key point is that a re-run of the SPD model may not be required to dispatch plant in offer order, respecting constraints also, over a period of less than 5 minutes[55]. This does not imply that energy bids are an appropriate basis for tracking all minor deviations, only that such dispatch need not be delayed once it becomes clear that it is required.

The remaining questions are whether units can sensibly respond based on energy market offers with a 5-minute period and, more importantly, whether they would be willing to respond. Willingness is important and will be addressed later as a transition matter, but it seems reasonable to expect that participants would be willing to respond to a relatively slow moving component of the RTP. Indeed, the AGC already has a facility, currently disabled, that supports the economic (energy market) dispatch of units to correct time errors, a slow moving component of the system error that AGC regulation attempts to correct. It should be relatively straightforward to recommission this with participation factors based on the current SPD rankings as discussed above.

This proposal is intended to reduce that part of the FCAS requirement that is driven by the 5-minute and half hour time divisions established under the Code. It does not and cannot remove the need for FCAS to deal with the short-term physical imbalances that need to be dealt with as they occur.

[52] Supply-demand fluctuations at short time intervals have greater rates of change (but shorter durations and therefore MW impact) than longer term imbalances.

[53] And 5 minutes could be considered too short as well. One implication of the approach outlined in this sub-section is that the 5-minute boundary would lose its significance. The focus would be on a half-hourly energy market price (as now), with all activity within the half-hour in an energy deviations market.

[54] The ranking measure is termed the *reduced cost* of the offer variable and is a standard output from an optimised solution.

[55] Some adjustments to allow for trends in inter-regional flow within the 5 minutes may be desirable to minimise the risk of "hunting" driven by variations in the regional balance of generation. This would be an implementation issue.

3.5.4 Linking Real Time Pricing to AGC Regulation

Regulation AGC is currently the prime mechanism for managing small deviations. It works by making small power adjustments, via the AGC, as any persistent “drift” in the supply demand balance as detected through frequency and time error measurements. As noted above, some of this drift may be dealt with by adjusting the output of units based on their offer prices (as ranked by the SPD) as the need arises, rather than waiting until the start of the next dispatch period.

Such an approach by no means removes the need for an FCAS service to account for both small and large deviations over intervals of much shorter than the energy market dispatch timeframe of 5 minutes. Such responses cannot reasonably be dispatched under bid-based market logic. Further, rapid response usually involves higher maintenance costs, so it cannot reasonably be expected that the service will be willingly provided based on energy market offer prices alone, even if it were technically possible. If these services are to be priced under a real time pricing logic, some other means must be found for determining these prices, in a manner that is considered acceptable by the ACCC, and that is also consistent with the way the system needs to be operated in these timeframes.

The following discussion is of a conceptual nature. Given that any application will need to be tightly integrated to AGC operation for the reasons to be outlined, the possibilities will need to be reviewed in a more detailed study in that context.

The need for an increase or decrease in power injection is recognised in the AGC logic through a measure known as the “Area Control Error” or ACE. This is an estimate of the current power deficiency or excess in the whole system[56]. The ACE is determined by the following calculation.

Area Control Error (ACE) = - Constant * Measured frequency deviation.

Constant is positive and is determined empirically and is an estimate of the power deficiency (or surplus) in the system given the measured frequency error. It reflects the in-built tendency for load to reduce when the frequency drops, and vice-versa. A positive ACE implies a downward frequency excursion, and vice versa.

While the ACE can be measured in real time it is not a basis for immediate action when used to control units under AGC regulation. Rather, the measure is filtered over time, and may be modified in other ways – for example, to account for time error. *If through this filtering process the power error is assessed to be persisting, signals are sent out through the AGC over the SCADA to ramp up or down the units under regulation.*

This process essentially produces a series of error signals that drive MW corrections from enabled units. Short term fluctuations are dampened with a filter whose time constant is set to

[56] No regional boundaries are recognised at present in AGC regulation activity. This is the basis on which the FCAS services are considered to have few geographic descriptions as noted in the Framework. The assumption is that any minor incursions into inter-regional flow limits caused by AGC regulation action can be readily corrected in the next dispatch interval.

a suitably large value (of the order of a minute rather than seconds) to avoid premature reaction to small and short-lived ACE variations leading to hunting and instability[57]. At the end of each 5-minute period, the residual deviation is recognised and driven back to zero in the energy market. Thus there is a 5-minute re-set process that brings these MW deviations back into the energy market.

In the above process the aim is to drive the filtered ACE to zero by adjusting the outputs of generators under regulation AGC. In very broad terms:

- The filtered ACE is a measure of the accumulated power imbalance in the system that persists until energy market generation has "caught up". This is essentially the FCAS activity.
- The bid-based energy market then moves to "catch up" with the FCAS service, by trying to drive its output to zero but not succeeding as long as the disturbances that drive frequency deviations persist. This is essentially the role of the 5-minute dispatch process.

Now consider the following pricing logic[58]:

Real Time Price Increment = Constant * Filtered ACE

This would define a price increment that would be positive if the ACE is positive because more generation is required, and negative if the ACE is negative because less generation is required. How the constant is to be determined requires a more extensive discussion, but the short answer is that it needs to be "high enough to get the response desired, and no higher".

What is the basis for such a pricing formula? Real time pricing concepts along these lines were proposed in the early 1980s by an MIT research team under Schweppe and IES has carried out further work[59]. *However, the simplest perspective is to note that the pricing formula rewards behaviour that reduces the ACE, and penalises behaviour that increases it.* To see this, note that the energy deviations market payment would be:

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[57] In engineering control terms, the AGC implements a form of *integral action* to the task of controlling frequency and time error.

[58] Somewhat simplified for exposition purposes. A practical energy deviations pricing formula will also need to include the effected of the accumulated ACE described earlier so that the response necessary to drive the ACE to zero can be sustained until the energy spot market takes over.

[59] In essence, a pricing formula of this type arises from solving a problem that would maximise the benefits of trade over an electricity network (essentially as the NEM does now). However, in this problem we model the frequency dynamics of the system and impose an additional constraint defined, in essence, as a limit on the accumulated sum of the square of a system error (system error being the ACE, with a correction for time error control purposes). Using this approach, a measure of frequency performance is defined that is essentially the *standard deviation of the ACE*, which can be interpreted readily as a standard deviation of frequency (perhaps slightly modified). In any case, the standard deviation of frequency is a useful measure of total FCAS performance. The constant in the proposed pricing formula can be interpreted as the shadow price associated with the constraint defining the frequency standard to be achieved (measured as a standard deviation). Its value depends on the performance characteristics of all the participants in the trading arrangement and so it cannot be set explicitly in practice; iteration toward a suitable value is required.

Energy Deviations Payment = Real Time Price * Energy Deviation
= Constant * Filtered ACE * Energy Deviation

This payment is summed over all short term trading intervals. Note that the Real Time Price is a price increment (positive or negative) relative to the energy market price. The first line takes the form of a *covariance between prices and energy (power* interval duration)* when summed and averaged over a period. The second line is proportional to the covariance between ACE and the energy deviations of a unit (assuming that the mean of both ACE and energy deviations is zero over the half-hour).

A competing Market Participant would seek to maximise *the covariance between the ACE and incremental power output in order to maximise revenue. In a nutshell, the pricing formula would reward Market Participants who act to make the ACE smaller in absolute terms and would charge those would act to make it larger in absolute terms.*

Following this line, we quote from research carried out by Hirst and Kirby at Oak Ridge National Laboratory on this topic (Ref 7). After studying the nature of deviations in US electricity systems and analysing who was contributing to the deviations and who was fixing them, they observed that:

"Generation can be treated the same as load in terms of time-varying fluctuations. Generation fluctuations that are positively correlated with load fluctuations are providing regulation and should be compensated for that service. Generation fluctuations that are negatively correlated with load fluctuations increase the load following burden on the control area and should be charged accordingly. Thus while it may make sense to pay generators for making their units available to the system operator (a reservation charge), it may be more important to pay (or charge) generators for real time performance"

Real time pricing using a pricing formula along the lines proposed, suitably phased in, would implement such an approach.

Finally we note that the ACE formula does not estimate the power deviations that occur immediately after a large contingency. This would require an additional term based on the acceleration and inertia of the system. This is omitted in the AGC logic because it has no substantial effect once governors and load shedding have arrested the rapid acceleration or deceleration within the first few seconds of a large contingency. It may also useful to include explicitly a small power adjustment to account for the need to correct time error. So a pricing formula that could potentially deal with rapid response options as well as the slower moving ones currently dealt with by the AGC could be based on a modified Area Control Error defined as:

Modified ACE[60] = H * Acceleration + K * Frequency error + M * Time error

Where:

[60] Some adjustments would need to be made to such a formula if, for example, the time error became large and to account for the interaction with the energy market, but the principle would be the same.

H = system inertia

K = system power sensitivity to frequency

M is a weighting that would drive the system's time error to zero in a stable manner

This is essentially the same as the ACE but more sensitive to very short-term deviations. In some or even many cases the acceleration term could be omitted as it is now. The pricing algorithm will not be pursued further at this stage.

Of interest and importance to note is that a real time pricing formula for energy deviations based on the ACE, or a modified form of it, is capable of being implemented at sites that are not subject to central dispatch. This is so because both the ACE (the basis for setting the real time energy deviation price) and the energy deviations themselves can be measure locally.

3.5.5 Outline of an Energy Deviations Market

We are now in a position to outline the shape of an energy deviations market that could ultimately provide the primary market mechanism for most of the small frequency deviation management service and a substantial part of the large frequency deviation management service. The outline is not intended to be definitive as there are many issues to resolve before it could be implemented. It should also be noted here that the proposed market arrangement depends on acceptance by participants and the ACCC of an administered price formula as the basis for trading in energy deviations. This is not fundamentally different from the current situation in the energy spot market. It is also relevant that the participating parties be willing in some sense, and for this reason we would propose that participation be optional.

Relationship between the energy deviations market and the energy spot market

Ideally:

- the energy spot market should deal with energy produced or consumed over half an hour at a determined spot price; and
- the energy deviations market should deal with short interval variations in both energy and price relative to half-hourly averages[61].

It follows from this that both energy deviations and price deviations should average zero over half an hour, by definition. The real time pricing logic for energy deviations described in this sub-section should typically achieve an average value close to zero over most half-hours, exceptions being when there is a significant contingency resulting in a short-term price deviation spike. *In either case, the average deviation price over each half-hour would need to be added to the SPD determined prices (currently calculated each 5-minutes) to achieve an outcome of zero average variation*. The effect of this would be negligible most of the time but impose a price spike (or trough) at times when significant contingencies occur. This

[61] The effect of these two rules together is a short interval total price consisting of the energy spot market price and an energy deviations price increment.

would seem to be a reasonable approach but it should be reviewed after further studies on likely outcomes and consultation.[62].

In Section 3.5.1 we reviewed the relationship between the 5 minute dispatch price and the half hourly energy spot price, pointing out the discrepancy between pricing and dispatch and suggesting how that discrepancy could be corrected. Following the approach of the previous paragraph, we note that the average 5-minute price over half an hour equals the energy spot market price by definition. The deviation of the 5-minute price from the energy spot price is therefore a component of the energy deviation price. This is consistent with the correction suggested in Section 3.5.1.

In Section 3.5.3 we discussed the possibility of dispatching plant based on offer prices at intervals of less than 5 minutes. This could be implemented as an *option* for any participant with dispatchable units. If the Participant agrees NEMMCO could dispatch the unit in the following way:

- In the absence of any deviations requiring correction, the unit would be dispatched according to its energy market offers.
- Where energy price deviations occur (reflecting a MW deviations) the unit will be dispatched at a different level if the spot and deviation price in total warrants it. This dispatch should take priority over the further dispatch of units that might be enabled in the FCAS small deviations market.
- Units enabled for small deviation FCAS should be used to meet any remaining small frequency deviation requirement to the extent that units dispatched on the basis of offer prices do not have adequate ramping capability.

This would require some modification to the AGC dispatch algorithm. The effect of the change would be to limit the range of deviation prices in a manner consistent with the offer prices of participants and in accordance with their willingness to participate.

Relationship between the energy deviations market and the FCAS enablement markets

In this Section we have proposed spot enablement markets for FCAS to replace the current long-term contract approach. The proposed energy deviations market would reward actual performance in controlling deviations i.e. in current ancillary service terminology it provides a payment for *use*, at least for those participating. The question is whether an energy deviations market could or should ultimately replace the FCAS enablement markets proposed for the shorter term, either in whole or in part. We note the following:

[62] A close parallel is dispatch pricing during periods when inter-regional link flow limits are violated following a contingency. NEMMCO's determination on this matter (published on the NEMMCO Web site) essentially removes the effect of the price spike that would otherwise have occurred from the spot market price outcome. It can be argued that this approach removes the incentives for generators and other participants operating in the energy spot market to account for the possibility of such contingencies in their decisions.

- Payment for *use* is most relevant to the continuously operating small frequency deviation service. Under normal circumstances a use payment through the energy deviations market alone should attract sufficient players. However, there might be room for doubt when energy demand is pressing supply and there are high spot energy prices. For this reason, and to provide NEMMCO with assurance that it can meet its Code obligations for system security, we propose that the enablement markets for the small deviation service be retained for the indefinite future. We would nevertheless expect that the clearing price for small deviation FCAS enablement would generally be low compared with energy deviation prices.

- Payment for use will encourage large deviation responses but may not be sufficient to reward plant that is seldom used. For these services we would expect the clearing price for enablement would remain a significant part of the total payment package for these services.

In both cases we would expect the requirement for the enablement markets will remain, but the payments will be relatively small for the small frequency deviation service once the energy deviations market is established and tuned.

Relationship between the energy deviations market and non-dispatchable plant

Non-dispatchable plant (which includes most loads) does not take part in the dispatch process and therefore cannot take part in the current arrangements for FCAS provision. However, loads at points of off-take from the transmission network can usually be measured by SCADA accessible by NEMMCO and could therefore take part in an energy deviations market. In the longer term specialised local metering could be developed for greater accuracy.

Loads measured at distribution off-takes do not usually represent end users. There is therefore a question as to whether energy deviations measured at such points should be paid for, and who should pay. This matter will be deferred to the "who pays and how much" stage of this project. However, it should be noted here that, conceptually at least, both energy deviations and energy deviation prices could in principle be measured locally and packaged as a separate commercial arrangement, even for those who do not operate in the energy spot market. This possibility should be explored ion the "who pays and how much" stage.

Energy deviation market dispatch, pricing and settlements

There are several ways that the pricing of energy deviations could be organised. To some extent this depends on how the boundaries between the energy spot market and energy deviations market have been defined. *The following approach largely mirrors the current boundary between the energy market and the small frequency deviation FCAS service as implemented in the SPD logic at present. It should be reviewed and refined or modified after further study*. The approach assumes that a suitable pricing algorithm for energy deviations, based on the ACE logic used by the NEMMCO AGC, has been developed. In particular:

- The current 5 minute energy market dispatch and 5-minute pricing logic remains.

- At the start of each 5 minute period the deviation price is re-set to zero, reflecting the current dispatch and FCAS logic that brings all energy provided by FCAS in the previous 5 minutes back into the energy market at the start of the following 5 minutes.
- Each 5-minute period therefore starts with the 5-minute dispatch price as calculated by the SPD base on bids and offers.
- As time goes on, frequency deviations will occur and this will be reflected in the energy deviations price. The effect of the deviations price is to modify the effective price seen (or at least paid or received) by participating parties, either up or down relative to the 5-minute SPD price.
- At the end of the 5 minute period and the start of the next, the deviation price is re-set to zero, and the 5 minute price is updated as per the SPD, and the process repeats.

In an initial implementation, the deviation price (or a proxy for it) can be mated in real time with SCADA power readings to determine a payment schedule. Accumulated values could be stored rather than the full stream of data, although samples could be saved for auditing purposes and records of abnormal situations kept. SCADA level readings will not be appropriate for the faster acting providers such as governors and would only be acceptable in any case because the deviation payments would generally be small. Faster-acting providers would require local measurement devices to be developed, and the benefits of doing so would need to be assessed.

Risk management in the energy deviations market

They key feature of an energy deviations market is that the total trade at any instant (allowing for losses) would occur between a range of buying and selling parties and these transactions should balance, much as they do in the energy market. There is therefore the possibility of bilateral hedging to manage risks on both sides of the market. The trade would be on the basis of energy deviations rather than average energy. For example, in a given half hour in the morning "ramp-up" period, one party might find that it regularly had a payment to the deviations market, while another a reasonably regular payment from it. These parties could find it mutually agreeable to hedge these risks[63].

3.6 Summary of Proposed Approach to FCAS

Light on the Hill

For the light on the hill for FCAS we propose the following:

- Revised frequency standards determined through an economic analysis of the risks and costs associated with different levels of frequency control, bearing in mid the over-riding

[63] Depending on the details of implementation, there are likely to be many parallels between the energy spot market and the energy deviations market. While the possibilities will not be explored further here, it is possible that energy deviation market risk could be managed with standard energy hedges.

need to maintain a secure system. Noting the proposed review on frequency standards[64], NEMMCO should recommend to the NECA Reliability Panel that this review include the form of frequency standards and the corresponding FCAS requirements necessary.

- An energy deviations market based on real time prices determined through an algorithm closely linked to NEMMCO's AGC. The market would reward behaviour that tended to correct frequency deviations and time error deviations, and penalise behaviour that tended to cause such deviations.
- Spot markets in FCAS enablement, based on short-term bidding though the SPD process, to provide NEMMCO assurance in the case of small deviations, and to "top up" the remuneration for providers of the large deviation service. The market for each FCAS product would pay a common clearing price as determined through a short term bidding process and the SPD co-optimisation logic. These would be a continuation of the spot enablement markets in FCAS proposed for the transition. When running in parallel with the energy deviations market, however, the dollar turnover in these markets would be much less than when first established.
- FCAS enablement product definitions would be revised to minimise current anomalies and technology biases.
- FCAS providers would not only be dispatchable plant as at present, but also non-dispatchable plant including flexible loads. Provider facilities could be embedded deep within distribution networks and provide services in addition to FCAS.
- There would be no requirement for long term contracting by NEMMCO in the small deviation service and it is likely that this will not be required for the large deviation service. However, this matter should be kept under review.
- There would be a requirement for potential FCAS providers to register their capability with NEMMCO.

Transition

For the transition we propose the following:

- Commence a review of FCAS product definitions[65] with a view to distinguishing more clearly the ability to respond to different frequency conditions over a range of time horizons. Pending the review of FCAS product definitions, FCAS product definitions should be modified to the extent supportable within the existing SPD logic.

[64] The NECA Reliability Panel has a proposal to undertake a cost/benefit analysis of frequency standards in 2 years time when data is available.

[65] The product definitions of 6 second, 60 second and 5 minute raise and lower that define the small and large deviation frequency control services.

- Undertake a review of frequency standards and the FCAS requirements to meet those standards in a robust public process. Noting the proposed review on frequency standards[66], NEMMCO should recommend to the NECA Reliability Panel that this review include the form of frequency standards and the corresponding FCAS requirements necessary.
- Early establishment of one-way spot markets in FCAS enablement, as described above, including the removal of the requirement for NEMMCO to contract for the small deviation service.
- During the transition period long term contracting between NEMMCO and providers may be retained to provide any residual needs for the large deviation service. Long term contracts with units supplying a governor response should not be required.
- This may also include the establishment of initial vesting arrangements that would allow the spot FCAS enablement markets to begin with minimal financial exposures. These should phase out gradually over some defined period.

These proposals should be refined and modified as necessary after consideration during the “who pays” stage of this project.

[66] The NEAC Reliability Panel has a proposal to undertake a cost/benefit analysis of frequency standards in 2 years time when data is available.

4 Network Control Ancillary Services

4.1 Overview

In this section we consider the services we have grouped together as being primarily concerned with maintaining the *operational efficiency and capability of the network* within its secure operating limits. These network characteristics in turn affect the extent to which Market Participants will trade energy over the network. In each trading interval, the SPD model calculates a dispatch pattern that *maximises the benefits of trade* using participant bids and offers, subject to the limitations imposed by an approximate physical model of the network and various security constraints imposed on its operation. The security constraints in turn are affected by the availability of NCAS. The electricity system is then operated according to the dispatch pattern determined by the SPD and energy spot market accounts are settled using the prices determined in the SPD process.

This algorithmic approach to dispatch determination and price setting was accepted by the ACCC in its Determination on the Code as an appropriate price determination mechanism for the NEM, given the particular technical requirements for operating an electricity system.

We first review the common aspects that appear in the Framework Classification Matrix before considering a general approach to NCAS.

4.2 Review of Framework Classification Matrix

4.2.1 Cause of the Requirement

There is a generally common cause for each of the following services defined by the Framework:

- Voltage Control – contingency;
- Stability; and
- Network Loading Control.

In brief, that common cause is the requirement to keep the network operating in a secure manner as load changes or after a contingency in the system i.e. a large generator or outage of a critical network element. The requirement to maintain a secure system is one NEMMCO's obligations under the Code, although that obligation only extends to the boundaries of the distribution systems. Thus the security of the system as a whole, especially as seen from the end-user's perspective, is a joint responsibility between NEMMCO and distributors.

As a general rule, NEMMCO can always maintain secure operation of the network by keeping power transfers across the network within secure limits. The mechanism for doing this in the NEM is generally through the imposition of generic constraints in the SPD model. Such constraints, if they become binding, change the disposition of flows and affect energy spot market prices. In the extreme, such constraints, if binding, can also affect the *reliability* of the system. For example, if the supply of one of some of these ancillary services were to be limited for some reason, network power transfers might not be able to support the entire load in some regions or zones, and some load might need to be shed as a result. On the other hand, the more usual situation would be that load is fully supplied but that some potential benefits from further trade might not have been realised.

A NEMMCO document (Ref 6) outlines the process followed for the dispatch of these services. In general, the requirement for these services is assessed on the basis of pre-dispatch outcomes without reference to benefits or costs. Further, the Procedure outlines steps to be taken, including direction of some participants, if NEMMCO assesses that the system would become unreliable in the even of inadequate provision of a particular service. It should be noted that TNSPs currently have a responsibility to procure ancillary services to support transfers within a region (see Appendix 3).

The requirement for this service is largely driven by the need to maintain voltages within certain bounds to keep within equipment tolerances, to manage network losses and, in some cases, to maintain QoS to some voltage-sensitive customers[67]. However, the requirement for the Voltage Control-Continuous service is also driven by contingencies that could cause voltage collapse. For example, voltages may be maintained a little higher than strictly necessary to reduce post-contingency voltage excursions; in this way there is some similarity with the Frequency Management – Small Deviation service

The cause of the requirement for the Enhanced Spot Market Trade service is listed in the Framework as simplifications in the current market design that:

- Do not schedule and price reactive power; and
- Approximate nodal pricing on a regional basis.

The inability to schedule and price reactive power and some of the approximations in the determination of nodal prices are partly the result of using a simplified embedded network model within the SPD. This model does not represent the underlying physics of the network accurately and in some respects at all e.g. with respect to voltages and reactive power, as well as the connected distribution networks. However, the approximations in the underlying physical model are by no means the only reason that current market does not capture some potential benefits of trade. Specifically, generic constraints that define security limits on the basis of available ancillary services and dispatch patterns have been implemented with many factors fixed (e.g. ancillary service availability) that in fact are variable (not necessarily continuously). This is a major theme of this section and will be discussed in more detail later. However in broad terms, spot market trade can be enhanced by:

- first, making the existing SPD network model work more effectively by allowing some factors to vary in the model that were previously fixed; and

[67] This would only apply to some high-voltage customers electrically close to the transmission network as voltage control for lower voltage customers is maintained by local equipment.

- in the longer term, moving to replace the current approximate network model with a more accurate physical model which, in particular, deals with voltages and reactive power[68].

4.2.2 Driver for Quantity of Requirement

For the three contingency-driven services listed at the start of the previous sub-section, the quantity of the requirement is driven by the size and location of each contingency and the pre-contingency dispatch and resulting network flows (as limited by generic constraints applied in the SPD process). Note that ancillary service providers can support several credible contingencies simultaneously. As will be discussed later, the most critical relationship here is between pre-contingency flows and the quantity of the requirement. This relationship is currently expressed in the generic constraints applied by NEMMCO to the SPD process.

4.2.3 Technical Options for meeting Requirement

The technical options naturally relate to the technical aspects of each service.

The Voltage Control services depend on the disposition of a wide range of sources and sinks of reactive power and reactive power capability. Some of these sources, such as reactive power management capability on the demand-side, are not presently captured explicitly in the NEM arrangements. Sources and sinks relate to generators and loads, specialised facilities designed to produce and absorb reactive power, and the transmission and distribution lines themselves. They have dispersed ownership and a wide geographic distribution. The geographic impacts tend to be local in a direct sense but can affect secure flow limits between regions as well.

Stability is managed with specialised voltage management equipment and fast-acting load shedding and protection schemes.

Network Loading Control is effected by managing pre and post contingency loads over critical network elements. In general, if network element loadings can be restored to within long term ratings after a contingency by one means or another, the more the network can be loaded up pre-contingency (other constraints permitting).

The Framework lists generation and demand, various network devices and network outage management as the technical options for Spot Market Trading Benefits. However, it could be more appropriate to list enhanced SPD logic as the key technical option in this case.

4.2.4 Measurements of Provision and Cause

SCADA is the primary means of measurement, with some specialised high-speed metering required in some cases. However, as this group of services is substantially concerned with meeting contingencies, it is also necessary for the system operator to be confident about *capability* i.e the ability of a provider to deliver reliably when called upon to meet a

[68] Such models, based on AC load flow theory, are currently used for operational or off-line purposes in the NEM e.g. to set parameters in generic constraint equations. One of the intended outworking of the NECA Transmission and Distribution pricing report is an assessment of nodal pricing.

contingency. Capability is not readily measured directly except when the contingency occurs and the actual response measured. Reliability is checked through a testing program required by the system operator in the supply contract. Beyond this, notification to the system operator of actual or potential availability, typically through the SCADA system, is taken to be a sufficient indicator of capability in day-to-day operations. It is worth noting here that ancillary service contracts are likely to retain some physical elements in them, in contrast to energy contracts in the NEM which are generally of a financial rather than physical nature.

4.2.5 Geographical Considerations and Potential for Competition

For all the network-related services there are geographic considerations that will be factors in any consideration of possible competitive arrangements. Generally, but not entirely, the services affect the secure limits of flows that can be sustained over inter-regional links as well as intra-regionally. The sourcing of the service may be regional or zonal but this may not imply in all cases that there is little scope for competition. In particular, if the demand for a service is not fixed but directly substitutable within the energy market, the scope for exercising market power in the provision of these services may be limited. The basis for this was discussed earlier in Section 2.

4.3 Relationship between NCAS and the Energy Market

4.3.1 Demand for Network Capability

In this sub-section we examine the following propositions that link the supply of NCAS to energy spot market outcomes:

- The primary purpose of NCAS is to maintain and increase the secure operating limits of the transmission network in accordance with the security crisis within which NEMMCO is required to operate.
- Since these secure operating limits must be respected in system operation, they are imposed by NEMMCO as "security" constraints (termed generic constraints) that limit the spot market outcomes.
- It follows that, if such constraints are binding (i.e. affecting energy spot market outcomes), there is a link between the supply of particular forms of NCAS and the amount of trade that can be realised over the network at any time. Further, a shadow price can be attributed to NCAS though this process.

NEMMCO has a Code obligation to operate the system securely. In the case of the network the current Code requires that dispatch and ancillary services be organised in a way that the network can withstand a single contingency without placing the system as a whole at risk or imposing enforced load shedding[69]. For a given availability of network assets and NCAS, NEMMCO (or its predecessors) have determined the secure network capability in off-line

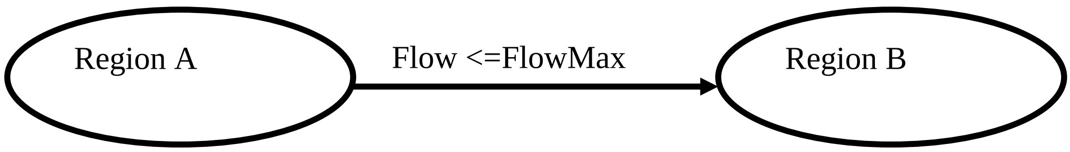
[69] That is, load shedding other than that organised under some commercial arrangement in which the load shedding entity is willing to provide the service.

studies. *The basis for setting these limits in that process is an important matter for this brief, as we have been asked to comment on the basis for determining the quantity of the requirement for each ancillary service. The issue is addressed separately in Section 4.4. In this sub-section we focus on the relationship between NCAS and the energy spot market given that these security limits have been set in some manner.*

As noted in Section 2, in the spot market SPD process secure operational limits in the network are expressed in terms of *generic constraints* on the pattern of dispatch determined by the SPD model. There is potentially one constraint arising from each possible network contingency and for each of the technical issues that need to be managed post contingency - voltage, stability and network loading. Because of the way the NEM defines regions[70], the constraints will bind most often on inter-regional flows; generally, intra-regional flow constraints will bind only when a network asset is out of service for some reason. In practice, the number of constraints that could bind at any given time is limited, even though the number of possible constraints is quite large. It should be noted that some constraints might bind infrequently because ancillary services have been procured that ensure such an outcome.

To illustrate the out-workings of this NEM logic, consider two regions where the inter-regional link between them has a limited secure transfer capability FlowMax as shown in the Figure 4.1 below:

Figure 4.1 Two Regions Connected by an Inter-regional Link



In the SPD this limit will be expressed as a generic constraint of the form:

Flow <= FlowMax[71]

Flow is a variable recognised by the SPD logic and its value in any run of the SPD model is determined by the current offers and bids well as the parameters of the network model. In the SPD solution, the variable Flow will satisfy the constraint; it will either be *non-binding* (strictly less than the limit FlowMax) or *binding* (equal to FlowMax) and limiting any further realisation of spot energy trading benefits.

[70] Regions are to be determined by electrical areas where internal constraints are not expected to exceed 50 hours per year (reference).

[71] In mathematical terminology (and linear programming terminology in particular), the variables are conventionally grouped on the left-hand side of the equality or inequality and are generically labelled the LHS. The constant is conventionally placed on the other side and is conventionally labelled the RHS.

The limit FlowMax is influenced by the range of ancillary services enabled as well as the disposition of generation and loads. As currently implemented in the NEM, the limit FlowMax is calculated *prior* to the SPD optimisation, largely by operator inputs of enabled services or SCADA readings that give the status of the service. The flow limit is calculated for each constraint affecting this flow, based on the available ancillary services and the dispatch in the previous interval. The lowest limit so calculated used in the SPD, as it is the one that would bind first. *In either case, FlowMax is fixed prior to the optimisation and the elements within it take no further part in the SPD process.*

Associated with each constraint in the SPD is a shadow price, which can be interpreted as the marginal value to the objective[72] for a marginal change in the constraint (e.g. a change in the RHS). In the case of a flow constraint this can be interpreted as the amount participants in the energy market would be prepared to pay for a marginal increase in the flow limit (RHS). With this interpretation we can ask how this value might vary with the RHS value i.e. the amount affected by the provision of ancillary services (and sometimes dispatch patterns). The example shown in Figure 4.2 has been obtained from IES's PROPHET market model by systematically varying the limit on an inter-regional constraint and observing the price difference across the constraint in the optimised SPD solution. The price should be interpreted as a price that parties operating in the energy market are prepared to pay for an increment of that capability[73].

This curve can be interpreted as the demand curve for link transfer capability. It exhibits the usual form of a demand curve i.e. a price declining with volume. The steps in the curve reflect the pattern of demand and generation offers into the various market regions. *It should be noted that the shape of this curve varies strongly with the conditions in the energy market; in general it will be steeper at times when supply in the receiving region is constrained*.

Intra-regional constraints do not have a well-defined single flow over which a limit applies. Rather, each constraint is expressed as a *function of generation and loads* on the LHS, and a RHS constant that depends on ancillary service availability (determined outside the optimisation), as follows:

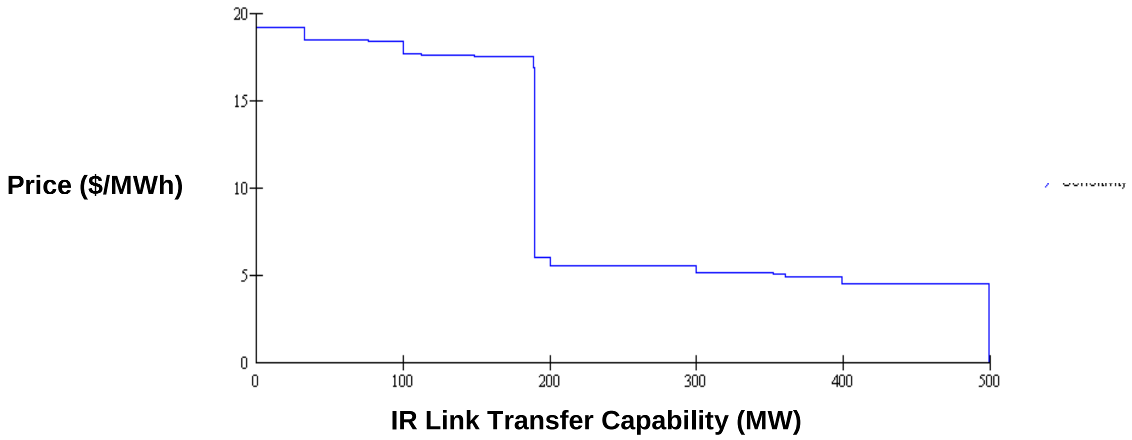
(Function of generation and loads) <= RHS Limit

In this case we can also vary the RHS and observe how the shadow price of the constraint varies, defining a demand curve for this particular capability. *Interpreted in this way, the logic described in this section applies to both inter-regional and intra-regional constraints.*

Figure 4.2 Example of a Demand Curve for IR Link Transfer Capability

[72] In the SPD model the objective is to maximise the benefits of trade over the network, given the current bids and offers. In fact, the objective as implemented is a modification of that to account for intra-regional losses.

[73] This information is of relevance to the possibility of actively offering a price (the Toll) for entrepreneurial link transfer capability into the NEM dispatch process, an option canvassed in the "Safe Harbour Provisions" paper issued by NECA (available on the NECA Website).



4.3.2 Supply of Network Capability through NCAS

The supply of NCAS as it affects a particular network generic constraint is contained within the terms that make up the RHS of the constraint relationship. To re-state the constraint:

Function of generation and loads <= RHS Limit

Or expressed in more general terms for each constraint:

Demand for secure network capability <= Supply of secure network capability

The table on the following page illustrates the transient stability constraint applying to exports from Victoria to NSW/Snowy, after the new Rowville (Victoria) transformer scheduled for November 1999 has been installed. The critical contingency is a Hazelwood-South Morang fault. The equation shows the "intercept" (constant) together with an array of terms that will affect the RHS calculated just prior to the dispatch. The general form of the constraint is:

Transient Export Limit (MW) =

Equation Constants + Sum of (Equation Variable * Variable Coefficient)

Equation Constants	**Coefficients (with series caps.)**
Intercept	+1664
Confidence level	-28.44*1.65
Safety margin	-50 for NSW transfer -25 for SA transfer
Equation Variables	
Power transfer from Vic. To SA	0
Square of (Power transfer from Vic to SA)	-11.66E-4
Victorian demand	-0.290
NSW demand	+0.0742
Inertia of Kiewa Hydro + Eildon Hydro	+16.20
Newport D inertia	+9.172
Inertia of Latrobe Valley generators connected to 500kV network	+3.535
Inertia of Latrobe Valley generators connected to 220kV network	+7.311
Inertial of NSW generators excluding Snowy	-2.275
Total inertia of Snowy generators, S/Cs and pumps	0
Anglesea generator flag (1 = on, 0 = off)	+113.8
Number of Tumut 3 pumps in service	0

Source: VPX

Inertias appear predominantly in this transient stability constraint but other terms are also present. In this case, the contribution is mainly determined by commitment-type decisions; there is no dispatchable generation. Note also that the demand side is represented as regional aggregates. In other cases also, including voltage contingency constraints, the demand-side is crudely represented in these constraints.

There is also a constraint covering the same Vic to NSW Snowy link, but arising from a different technical requirement, namely to stay within the thermal limits of certain transformers (post Rowville and with series caps installed).

Thermal Export Limit (MW) =

Equation Constants + Sum of (Equation Variable * Variable Coefficient)

Equation Constants	**Coefficients (with series caps.)**
Intercept	+85.41
Confidence level	-17.9*1.65
Safety margin	0
Equation Variables	
SMTS F2 500/330kV Transformer rating (normally 1000MVA)	+1.904
Victorian demand	-0.4158
Total Kiewa hydro generation	+0.852
Newport and Anglesea generation	+0.267
Eildon generation	+0.764
Total gen. of Latrobe Valley gens. connected to 500kV network	+0.444
Total gen. of Latrobe Valley gens. connected to 220kV network	+0.113

Source: VPX

In this case the supply depends on the pattern of generation dispatch as well as demand. Although not done so at present, in principle the generation terms could be moved to the LHS as variables. This is guaranteed to improve or at least maintain the value of the objective (i.e. to achieve greater benefits of trade where possible) for a given set of offers and bids, relative to the case where the limit is calculated as a fixed number based on immediately previous dispatch levels.

As a general rule, bringing a variable from the RHS to the LHS of the generic constraint equation and co-optimising this variable with the rest of the dispatch provides an opportunity to improve the benefits of trade (in both energy and NCAS), all else being equal.

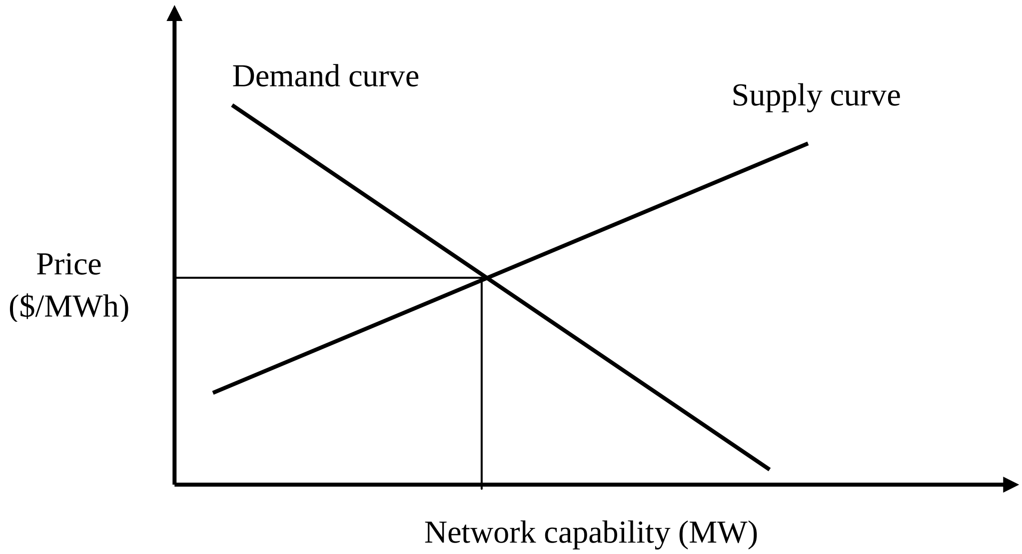
This states the truism that an optimisation process (in this case, the optimisation that takes place within the SPD logic) will always give a better result if a constraint is relieved. In this case, the constraint is relieved by moving fixed NCAS on the RHS to variable NCAS on the LHS of the generic constraint equation[74].

The above observation does not necessarily imply that moving all NCAS to the LHS to be co-optimised with the energy dispatch is necessarily an appropriate policy prescription, much less provide the basis for establishing a market. There is a range of other factors to consider. However it does provide a framework within which the NCAS can be shadow priced and the possibility of establishing markets in some of them examined.

[74] It is important to note that a short dispatch interval (currently 5 minutes) is *not* a substitute for co-optimisation.

We can illustrate this possible supply model for network capability (through the impact of NCAS on a binding constraint) by stacking up the NCAS supply options in price order and relating that supply curve to the demand curve for the network capability as previously discussed. This is illustrated in the Figure 4.3 below.

Figure 4.3 Supply and Demand for Network Capability (one generic constraint)



The intersection of the supply and demand curves gives the equilibrium price and quantity for the secure network capability defined by this constraint.

4.3.3 Price Interpretation and Settlement Logic for Generic Constraints

Generic constraints give rise to shadow prices and the *potential* (not necessarily implemented) for financial transfers between market participants through the NEM settlement process. Consider how this works for transactions affecting the energy balance within a region in a given trading interval. The settlement logic is usually taken for granted but it arises, or is at least consistent with, the representation of each regional energy balance constraint within the SPD model.

The regional energy balance is in the general form:

Regional energy demand – Regional energy supply = 0

where supply and demand include losses, region imports and region exports.

Within the mathematical formulation of the SPD optimisation and its solution this appears in the form of a term:

Regional energy price * (Regional energy demand – Regional energy supply)

Since the term in brackets is zero the whole expression is also identically zero[75]. *The regional energy price* is the shadow price associated with the constraint in the SPD solution. This is interpreted as the 5-minute SPD regional energy price from which the half-hourly regional energy market price is calculated.

Each of the terms in the above relationship leads to an idealised settlement transaction:

Incoming payments = Regional energy price * Regional energy demand

Outgoing payments = Regional energy price * Regional energy supply

NEMMCO settles both of these cash streams but remains financially neutral in this idealised case[76]. Demand and supply are both split into components corresponding to the transactions of each participant.

Now consider a generic constraint. Such constraints are similar in most key respects to regional energy balance constraints, but the following differences should be noted:

- Generic constraint expressing security limits are normally expressed as inequalities (e.g. "equal to or less than". rather than equalities; and
- They express a desirable (i.e. secure) operating state rather than a physical law, implying that they may sometimes be violated either deliberately or inadvertently.

However, the same settlement logic could apply. Consider a simple inter-regional limit:

Flow <= FlowMax

In the SPD logic this appears as a term:

Constraint shadow price *(Flow - FlowMax)

If the constraint is not binding, that is, if Flow < FlowMax, then the constraint shadow price is zero; otherwise it may attain a positive value[77]. Consider now the more interesting case when the constraint is binding. The following settlement transactions *could* arise for NEMMCO:

Incoming payment = Constraint shadow price * Flow

Outgoing payment = Constraint shadow price * FlowMax

The incoming payment represents the constraint residue that arises from the pricing and dispatch process when this inter-regional constraint binds[78]. This accumulates from

[75] In practice, some allowance must be made for metering errors and approximations in the network model, but the principle remains unchanged.

[76] Adjustments in losses in fact result in a small "residue" from this transaction.

[77] However, the product of the shadow price and the constraint value (the term in brackets) is always zero at the optimum. This is a fundamental property of an optimised solution.

[78] Loss residues also arise separately, the two together making up the total residue accumulating from trade over inter-regional links.

NEMMCO's settlement process and can be identified explicitly within the total pool of settlement residues.

The outgoing payment is immediately identifiable as the payment made to the recipient of the relevant inter-regional settlement residue[79]. We understand that this has been determined by NECA to be the receiving region for which the inter-regional constraint applies[80].

While these transactions do occur with respect to inter-regional constraints, under current NEM rules they are not always implemented for intra-regional constraints. For example, if an internal network constraint "constraints off" some generation, the generator gets a lower dispatch volume but still receives the regional price (loss adjusted) for the remainder. It is easy to show that this arrangement essentially "hands back" the constraint residue to the constrained-off generators. Such generators are not dispatched according to the price they receive, which is not strictly in accordance with the dictum in this project that dispatch and pricing should be compatible[81].

Now consider the components that make up the flow limit FlowMax. As noted in the previous discussion, this limit (currently the RHS of the constraint equation) is made up as follows:

FlowMax(MW) =
Sum of equation constants + Sum of (Equation Variable * Variable Coefficient)

The equation variables are currently calculated just prior to the dispatch and are part of the constant RHS as far as the SPD is concerned. As noted in the previous examples, the variables can be expressed in terms of the factor influencing the limit (e.g. inertia) or some proxy to it; the corresponding coefficient converts that variable to its contribution to the MW limit however the variable is defined.

With this relationship, the outgoing (from NEMMCO) payments can be now be expressed as:

Outgoing payment = Constraint shadow price * FlowMax =
Sum of (Constraint shadow price * Equation constant) +
Sum of (Constraint shadow price * Equation variable * Equation co-efficient)

In other words, even if the variables are not or cannot be co-optimised by bringing them to the LHS of the generic constraint, they can be shadow priced explicitly as an output of the

[79] This and the associated loss residue is colloquially known in the NEM as "black hole money".

[80] The details of this Determination were not to hand at the time of writing. It should be noted that the prime recipient may have auctioned that settlement stream and receive only the premium from that auction.

[81] If the settlement logic associated with this constraint were to be implemented, it would result in a lower net payment to the generator. This probably explains why generators seem to live with this rule, despite the inconvenience and risk of being constrained off.

SPD and settlement processes[82]*. This process does not necessarily imply that payments must or should be made in accordance with this allocation; the merits or otherwise of such an approach requires examination.*

To summarise, once limits on secure network operation have been set through the imposition of generic constraints in the SPD, NCAS attains value through its contribution to improving the benefits of energy trade over the network. The NEM expresses this relationship as a series of generic constraints applied to the SPD process that define a secure operational envelope for the network. Components of those constraints include generation and loads, as well as particular ancillary services as defined in the Framework. In principle, the dispatch of at least some of these services could be co-optimised with the energy dispatch by bringing the corresponding ancillary service variables from the constant RHS of the generic constraint to the variable LHS. Whether this is done or not, the marginal benefits of trade in the energy spot market for each service entering the constraint can be calculated for each energy spot market trading interval. The sum over all constraints of these individual contributions (noting that one provider can provide capability that effects more than one constraint) gives the value to the energy spot market (at the margin) of each service provided.

As noted earlier, the basis for setting the secure operating envelope for the operation of the network is considered further in Section 4.4.

4.3.4 Some Issues arising from NCAS Shadow Pricing Logic

In this section we consider some practical issues that arise from the NCAS shadow pricing logic described above, before considering the possibility of building on this logic to develop markets in NCAS.

Under what conditions might a specific NCAS be co-optimised with energy within the SPD logic? Co-optimisation in the SPD implies that the particular service be dispatchable i.e. subject to instruction by NEMMCO as to its required operating level, as determined through the SPD process. At present, this is not possible for continuous voltage control (i.e. reactive) because the SPD excludes it. There are, however, several cases where co-dispatch might be feasible and desirable.

In cases where generator energy dispatch volumes are present in the generic constraint such as in the Network Loading Control example given in Sub-section 4.3.2, co-dispatch would be relatively straightforward extensions of the current dispatch logic and, further, bidding facilities are already available under the current NEM arrangements. In essence, the only technical requirement would be to bring the RHS energy dispatch variables over to the LHS in the effected SPD model equations and to implement the corresponding settlement arrangements (to be discussed further later).

[82] The relationships may need to be linearised if initially expressed originally in non-linear terms. Further, the pricing occurs "at the margin", and this leads to some qualifications in the application that will be discussed later.

Another example could be the reactive capability necessary to provide the Voltage-Contingency NCAS. In the case of generators, "backing off" some energy production can enhance this capability, but the relationship is much weaker than in the case of FCAS and energy. This will be considered further in relation to the particular service. While the possibility could be reviewed later, we doubt that co-optimisation of this service would be warranted at this time.

In most other cases the capability offered or provided would be relatively lumpy or "on-off". In these cases, the capability would be either present or not, and included on the RHS of the relevant generic constraints as at present. However, these services can still be shadow priced with reference to the spot market using the logic previously described. Further, in some circumstances a competitive market arrangement might still be established based on this logic. Under such an arrangement, potential providers would simply make commitment or availability decisions based on their expectations of spot market outcomes, for example as might be gleaned from initial pre-dispatch results. They would then simply accept the price outcome from the SPD process. While they would be price takers in the dispatch process they could influence price outcomes through their declared capability, so they need not be entirely passive. The behavioural incentives would depend on how competitive the spot market in the service was at the time as well as on the contracts that the provider might hold. This is discussed further below.

Where the NCAS capability offered is lumpy but sufficiently small, the shadow price of the generic constraint can be applied to the total capability to give a reasonable indicator of its value to the market. If the capability is large enough to shift the shadow price significantly (implying a corresponding significant shift in the spot energy market price outcomes), the shadow price cannot be taken as a complete indicator of its value to the market as a whole. This is a situation where economies of scale apply. Whether or not this limits the scope for competition should not be pre-judged as there may be many supply options even though only one or a few lumpy supply sources are required. If the facility adds value to trade and suitable competitive arrangements are in place, there is no reason to expect that a source of NCAS will not be procured as long as it adds enough value to energy trade, irrespective of short term price outcomes.

4.3.5 Scope for Markets in NCAS

Some pre-conditions for the establishment of markets are reviewed here in relation to the NCAS services discussed in this Section. The focus is primarily on the contingency-based services (i.e. those affecting the operation of generic constraints in the SPD). As noted in the Framework, these pre-conditions are seldom if ever satisfied perfectly, and the scope for markets needs to be established by examining the specific circumstances of each case.

Product Definition

The products traded in the NCAS group should be expressed in common units i.e. *MW of secure network capability associated with a specific technical factor and contingency affecting network security, as expressed in a SPD generic constraint.* This definition implies that the product is bought and sold in relation to a specific generic constraint as defined in the SPD. The SPD produces a spot price associated with the constraint, and therefore for the defined product. The definition supports both supply of NCAS affecting the constraint, and the demand for NCAS as expressed in the spot energy market. The definition could apply equally to inter-regional and intra-regional generic constraints.

It is important to note that this definition implies that there is a need for NEMMCO to define a relationship between a particular service and its impact on secure MW transfer capability (i.e. an "influence" coefficient). This is already done as an operational matter, but presents a challenge for the establishment of market arrangements.

It might be possible to define an NCAS product in more direct terms such as MVAR of reactive energy. Such a definition, while perhaps more intuitive, does not define a product for which a common price can be determined because reactive is so localised in its effect.

We note that a provider, and a particular facility operated by a provider, can jointly supply a number of NCAS markets (constraints). For example, a generator may provide reactive capability that impacts on several generic constraints. We note also that such a facility can jointly supply product to several NCAS types (e.g. Voltage–Contingency (reactive), Stability and Network Loading Control), as well as to the energy market[83].

Finally, we also note that several constraints may affect a particular network transfer capability, and that often these constraints are "close" in that one or the other might bind at a given time, and sometimes more than one. This closeness is not surprising, as the incentive is to relieve the constraint that is currently binding, but no more than necessary given other constraints may also become binding.

Firms as price takers

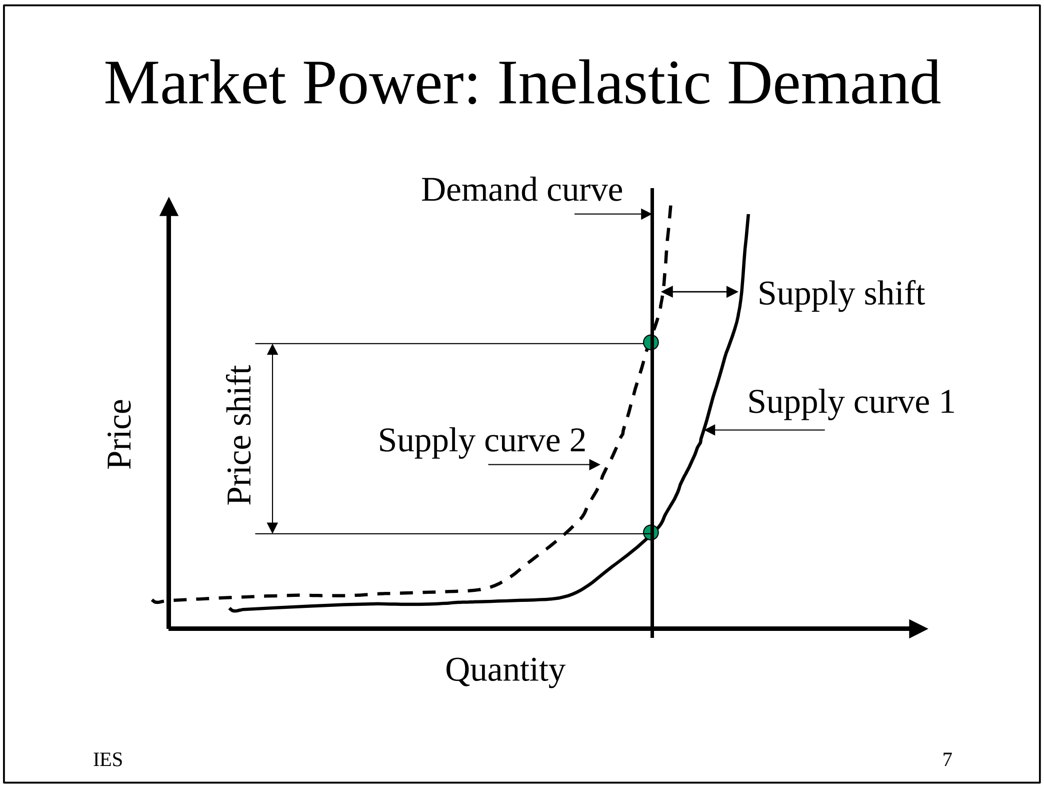
Unlike FCAS that can be provided reasonably universally over the whole system, NCAS tends to have a zonal or even a local basis, as it determines the transfer capabilities over portions of the network. Thus the scope for providers to exercise market power in the provision of these services is likely to be greater for NCAS than for FCAS. On the other hand, a significant part of NCAS will probably be in support of inter-regional transfers. In the long run, and for all but some occasions in the short run, inter-regional transfer capability does not generally hold a dominant market position in terms of energy supply; that is, there are reasonable substitutes available. Thus should two-way markets be set up in some NCAS,

[83] It should be noted here that there may be useful "higher-level" product definitions for the longer term. These would recognise, for example, that a particular capability to shed load at very short notice via a direct communications system is useful to deal with local network contingencies as well as a range of NCAS and FCAS as discussed in this report. If products were defined in these terms (perhaps with a local and regional dimension as well) rather than with reference to their application in dealing with a particular ancillary service, a pool of capability in this product could be developed that could be applied to a range of ancillary service and other applications in the NEM for profit. This would be a natural development from the lower-level product definitions defined here. There is no obvious reason why the exploitation of such synergies needs to be centrally organised, although it would be useful that they be highlighted in the Statement of Opportunities and perhaps promoted in other ways. This possibility will be noted as part of the light on the hill.

the scope for exercising significant market power may be more limited than would be the case with a single buyer meeting an "need" determined independently of value in the spot market.

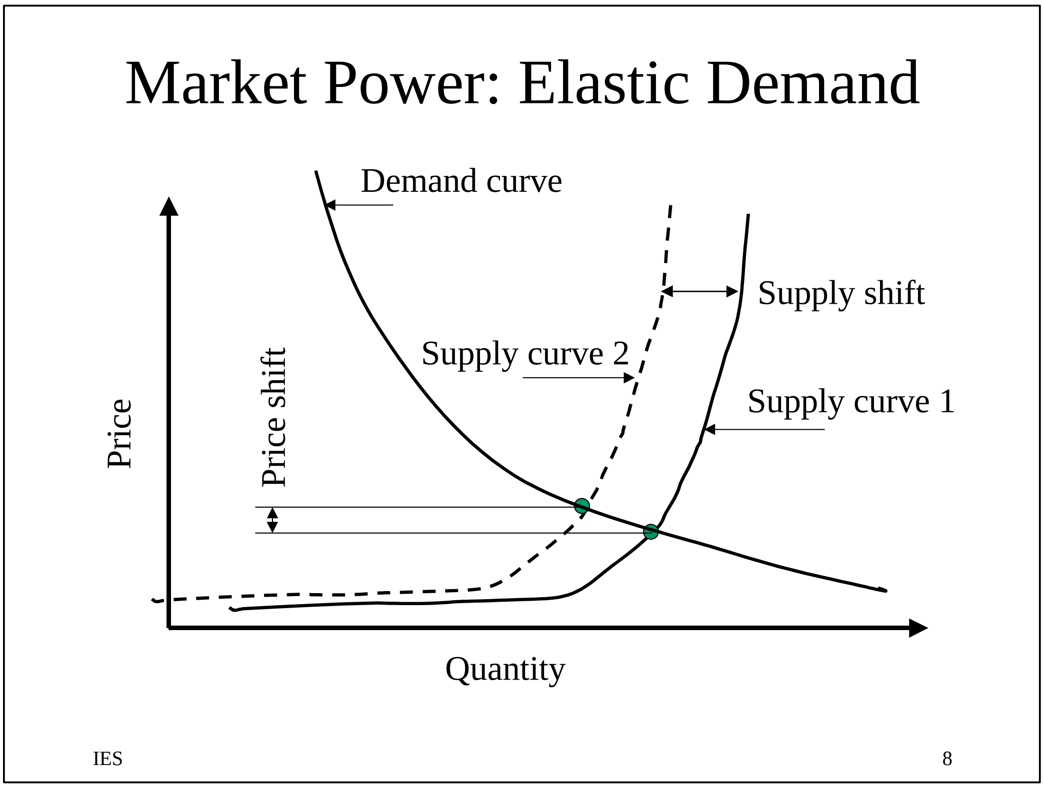
To illustrate this, consider the case below where NCAS in support of, say, a particular inter-regional transfer is to be purchased by a single buyer (NEMMCO) on the basis of a fixed, previously assessed "need". This gives a vertical inelastic demand curve for the NCAS concerned at the assessed level of "need". With this vertical demand curve, there is a significant price increase if one or may suppliers act to decrease supply (by shifting the supply curve to the left). This is shown in Figure 4.4 below. Such a price increase may more than compensate for the loss of volume, which provides an incentive to restrict supply.

Figure 4.4



The second case (Figure 4.5) shows a more elastic demand curve (as obtained by the logic described in Section 4.3.1), as would be the situation for much of the time in normal NEM operations. A corresponding shift of the supply curve leads to much lower price response and a correspondingly lesser ability for providers to exercise undue market power.

Figure 4.5



Mobility of factors of production

Many NCAS services are produced jointly either with energy or with some other market product. Load interruptibility is jointly produced with normal production, while reactive energy is often jointly produced or consumed with real energy. Load reductions can be achieved both by reducing voltage or frequency. On the other hand, in some important cases dedicated facilities can be installed to meet NCAS requirements. In the important case of reactive power provision, static capacitor banks and synchronous condensers are specialised facilities that can be installed where required.

Adequacy of information

Adequate and accurate information will be fundamental to the working of any effective arrangements for NCAS provision, including market arrangements. This need arises because the requirement for NCAS is NEMMCO's and the TNSPs application of security standards applied to the network. That implementation involves complex technical relationships. While these relationships are ultimately expressed unambiguously as generic constraints applied to the SPD process, many judgements are required in formulating them[84]. Further, the

[84] This judgement applies not only to the determination of the factors that affect the constraint and their relative contribution, but ultimately also to the weight that is to be given to possible violations of the constraint. These will occur from time to time as a result of contingencies. On other occasions it is conceivable that they should be allowed to occur because the risks are manageable, and appropriate in some situations, such as when load

process of arriving at them has commercial implications and must be transparent. It may be that the judgements required might preclude the possibility of markets due to the inherent external uncertainties that these judgements could impose on the trading process[85], but transparency is desirable in any case. The Reliability Panel would be the current forum appropriate for reviewing the formulation and application of generic constraints. This work would need to be accompanied by rigorous public review processes and regular publication and analysis in the Statement of Opportunities as provided for in the Code.

4.3.6 Related Issues

Bearing in mind these considerations, the scope for markets in NCAS will need to be considered in the circumstances of each case. Before proceeding to that task, we briefly consider some related issues.

Identification of buyers and sellers of NCAS

At present there is no incentives for the entrepreneurial procurement of NCAS. The parties who might wish to gain access to NCAS are broadly identifiable as those interested in trading over the network. NEMMCO, and the TNSPs within regions, are currently acting on their behalf to procure NCAS, but this may not be an enduring feature of the NEM. The NECA Transmission and Distribution Network Pricing Review is beginning to define how entrepreneurial network elements might operate. Further, the development of an inter-regional hedge market is likely to require, at some point, any supporting NCAS to be dealt with in a commercial manner. Conversely, until NCAS products become more clearly identified and priced, the development of such entrepreneurial arrangements is likely to be hindered. This suggests the merits of an immediate strategy to identify and price NCAS products, even though the prospects of establishing markets may be longer term.

To bid or not to bid

Current and proposed arrangements for FCAS provide for bidding for co-optimised dispatch through the SPD process. In the case of NCAS, the jointness of production with energy is rather weak in general and the case for co-dispatch of NCAS supply is less clear. On the other hand, the demand for NCAS is very much a function of energy spot market outcomes, as argued in this section. This in itself is not a compelling argument for co-dispatch. As argued earlier, much NCAS would be supplied through commitment rather than dispatch decisions, and such decisions are probably best made outside the SPD, but with good advance information. If this approach is taken, the case for facilities to allow providers to place floor prices on their enablement is not immediately evident. Such a facility could allow providers

would otherwise be shed. NEMMCO has recently made a determination on pricing in over-constrained periods that cannot be regarded as a long-term solution to the problem. We suggest that the proposed reviews of these constraints through the NECA Reliability Panel should recognise the possibility and desirability of assessing risks and defining "soft" constraints where appropriate.

[85] But the relationships could be kept unchanged for extended periods, such as a year or more, barring changed circumstances in the network.

to exercise market power when they would otherwise be mere price takers. On the other hand, omitting such a facility by no means prevents the exercise of market power by restricting NCAS supply. The question of whether NCAS bidding should be supported will depend on the particular NCAS. To the extent that an element of the NCAS is provided by already-dispatched energy plant, the matter is resolved. Reactive for contingency voltage control is also a candidate as will be discussed. At the other extreme, the case to support short-term-bidding to provide Stability services does not seem compelling at this stage.

Separation of energy and generic constraint prices

The NEM designers made considerable efforts (perhaps misplaced) to maintain simple relationships between the energy spot prices paid and received by participants within a region. In essence, all participants within a region see a single regional price adjusted by a constant loss multiplier applicable to each. Price differences between regions may be volatile but this can in principle be managed with inter-regional hedges. Generic constraints that affect price relativities between regions are consistent with this philosophy. On the other hand, intra-regional constraints, when applied and binding, change the dispatch but not intra-regional price relativities. This leads to a discrepancy between pricing and dispatch on such occasions.

The pricing arrangements that are proposed in this Section would leave the underlying energy market logic intact. They would, however, provide opportunities for additional trading around the more active generic constraints and such additional trading could be optional. Thus the proposed approach to NCAS pricing does not imply any necessary dislocation to current spot energy market price relationships.

Materiality and implementation costs

Current NEMMCO information suggests that the voltage control ancillary services are by far the most costly in this group. Spot Market Trading Benefits is not an identifiable category at present. The current expenditure on the other NCAS might not justify the effort of market development. This situation may change as networks become more intensively utilised. In any case the pricing logic described in this section would support the development of market arrangements should later consideration justify them.

4.4 Relationship between NCAS and System Security

Before proceeding to a review of particular services within the NCAS group, we consider the important matter as to how the limits expressed in the generic constraints should be set. The Code currently requires these to be set so that the system remains ”secure” in the sense that it can sustain a single contingency such as a line outage or fault without endangering the system as a whole or inducing non-commercial load shedding. Further, recovery to a secure operating state after a contingency should be achieved within a half-hour .

The technical issues behind such assessments are complex. However, the imposition of these constraints does incur a cost in terms of lost benefits of trade in the energy spot market. It is then legitimate to inquire as to whether mitigation of the security concern expressed in each generic constraint justifies the ongoing cost that it imposes on energy spot trading.

We note first that generic constraints are imposed to deal with *contingencies*. Specific contingencies within the high voltage transmission network such as unplanned line outages are likely to be rare events[86]. Further, the effects of a contingency if the corresponding generic constraint were to be relaxed does not in every case necessarily imply uncontrolled failure of the whole system. Some load might need to be shed or at least reduced, or two regions might separate electrically (called islanding). These raise issues of operational management and system reliability, all of which might be addressed in ways other than constraining spot trade through the imposition of generic constraints. Indeed, some of the current stabilisation and network loading control schemes had their genesis in a close review of operational options other than imposing such constraints, at least at their original level. The point is that imposing constraints on energy spot trading can incur ongoing costs that are out of balance with the real likelihood and consequences of the contingency concerned.

The following approach would deal with this issue and be sympathetic to the later development of market arrangements in NCAS where they would be viable. It would be applied to those generic constraints assessed to have the largest economic impact i.e. those that are most often binding and with large shadow prices. These should be readily identifiable by examining historical SPD records and be relatively small in number.

- NEMMCO should extract, interpret and publish the generic constraint shadow price data as outlined in the previous sub-sections, as well as information supporting the formulation of the relevant constraint. It should also publish data on constraints for which NCAS has been contracted, and which may seldom bind for that reason.

- NEMMCO should request the NECA Reliability Panel to implement a formal, rigorous and public process for reviewing each constraint, inter and intra-regional. Greatest weight should be given to those that bind most often, bind with high shadow prices or for which NCAS has been contracted for even if they do seldom, bind i.e. those that have the greatest economic significance. The review should cover the factors that affect the constraint, the consequences of and ways by which, it might be relaxed including the probability and consequences of the associated contingency, the benefits to energy spot trading of relaxing the constraint and possible ways of meeting the security concern in ways other than imposing such a constraint.

- NEMMCO should request the NECA Reliability Panel to determine the matter in each case, including the period over which the determinations should apply. Some assurance along these lines would be necessary to support any commercial activity in these services.

- All such information and activity should also be published in the Statement of Opportunities or in a companion document.

We note here that there is a close relationship between system security and system reliability in this area.

[86] But much more common within distribution networks.

4.5 Options for Particular Services

4.5.1 Overview

In this sub-section we summarise how the previous analysis can be applied to each type of NCAS. In all cases further analysis and debate is required before the merits of establishing two-way competitive markets in NCAS can be established. Some forms of NCAS do appear more prospective than others in that respect. In either case, a move towards greater price transparency and re-dressing some institutional imbalances in the consideration potential supply sources should lay the necessary foundations.

Analysis and discussion papers on the voltage services are at Appendices 2&3 and will be referred to in what follows. Appendix 4 is an example of enhanced spot market trading.

Before discussing each of the NCAS services separately, it should be understood that in all the arrangements proposed, NEMMCO would remain responsible for dispatch, spot pricing and for power system security. However, within this framework, parties (such as Market Participants, TNSPs and NEMMCO) may contract such services for the purposes of hedging and procurement.

4.5.2 Voltage Control Services Generally

Voltage control services and their interaction

Within the transmission network the factor that determines voltage outcomes in the provision and consumption of reactive power. There is a close relationship between the Voltage Control - Continuous and Voltage Control - Contingency services, just as there is for the two frequency management services. In essence, the continuous service requires the provision of reactive power at various locations to maintain voltages throughout the system, while a capability to produce reactive power at short notice is required to maintain voltages within acceptable limits after contingencies that might occur in the system. As with frequency management, there is some overlap between the two as voltages can be kept a little high on the continuous service in order to ease the demand on the contingency service.

The requirement for reactive power in both cases is very strongly dependent on system conditions i.e. the disposition of loads, generation and associated network flows, and is strongly location specific. Reactive power for continuous voltage control and reactive capability for contingency requirements are also joint products, in that the provision of one excludes the provision of the other. Further, the cost of producing reactive power is generally small once the appropriate device is committed and on line. It follows that the value of reactive power or capability for the continuous service and for the contingency service will tend to have the same marginal value at any given time, and this must be recognised in any market or pricing arrangement.

Generally, the contingency requirement is viewed in terms of a total requirement for reactive capability at the time, accepting that some will be used for continuous control and some held in reserve. The mix of reactive capability in terms of static and dynamic capability i.e the ability to respond rapidly to a contingency, is also important. Dynamic and static capability in this sense are distinguishable products, although dynamic capability can substitute for static.

Institutional arrangements surrounding voltage control

Some institutional background is contained in Appendix 3.

A feature of the voltage control services is the diversity of parties potentially involved in the production and consumption of reactive power, which is the prime determinant of voltage levels throughout the high voltage system. Specifically:

- Both the transmission network and distribution network wires can consume and sometime produce reactive power, depending on system conditions.
- Specialised reactive sources can be provided at both the distribution and transmission levels, and often one is a substitute for the other.
- End users also consume reactive power and have considerable scope through equipment design or the installation of specialised equipment to modify that consumption.
- Reactive power can be produced or consumed by generation equipment, the capability to do so depending on the level of generation, although this relationship is quite weak under most conditions.

The responsibility for voltage control is currently shared between the TNSPs and NEMMCO. With reference to the NEM Code, the TNSPs have a responsibility to maintain satisfactory voltage profiles (Chapter 5), while NEMMCO have the responsibility for overall system security also requiring the maintenance of acceptable voltage levels (Chapter 4). Nevertheless as an interim measure, NEMMCO has established agency agreements with the TNSPs for voltage control services[87]. (The TNSPs control regional voltage levels from their respective control centres).

In additional to these agency agreements, NEMMCO has entered into ancillary service agreements for additional reactive[88] (for system security purposes). This reactive is in addition to the reactive resources provided by mandatory generator connection agreements and by TNSPs reactive plant. The need for these additional voltage control services was the result of the current voltage control standards, and the balance of available voltage control resources and the assessed potential reactive demands of distribution companies at their point of connection.

The ancillary service contracts provide for additional generator reactive capacity at specific locations than is provided for by generator connection agreements. The form of the contracts

[87] The apparent Code inconsistency with regard to voltage control responsibilities is a matter that has been noted by NEMMCO.

[88] NEMMCO direct the use of synchronous condensers due to the high enablement costs.

has an availability payment and an enabling payment. There is no usage payment recognising the very low marginal cost of reactive production.

The main driver for the additional reactive capacity contracted by NEMMCO was the maintenance of network capacity at times of high reactive demand, considered necessary to maintain network capability. As such, these reactive ancillary service contracts services compete with other options such as location generation and demand side response that are integrally related to the top end functioning of the market. In this sense the competitive provision of voltage control services needs to be seen in the wider context of market efficiency (especially at the top end).

In addition to NEMMCO involvement, market efficiency and the potential for competition is currently clouded by the apparent Code inconsistencies and different incentives that apply to the Transmission Network Service Providers (TNSPs), Distribution Businesses (DBs) and generators in respect to these services. In particular:

- The incentives and responsibilities of TNSPs, that have voltage control services "bundled" in with the regulated assets (in accordance with TNSP planning criteria).
- The incentives for DBs to control reactive withdrawals (although the Code does provide power factor standards that can form the basis for TNSPs and DBs to co-operate in the provision of reactive sources such as capacitor banks).

Proposals for institutional changes in relation to voltage control

In summary, the Code appears to signal joint responsibilities in some areas relating to voltage control and has been subject to different interpretations in other areas. Of note is that the Code:

- signals both TNSPs and NEMMCO to have responsibilities in regard to voltage control service;
- provides NEMMCO with the overall responsibility for coordination of intra and inter-regional network planning;
- provides for TNSPs and DNSPs to cooperate in the development of optimal planning, and while it does place a requirement on DNSPs to maintain reasonable power factors, it may not provide clear commercial incentives to these parties;
- has been subject to interpretation as to the responsibilities of TNSPs in regards to maintaining inter-regional capability;
- is silent on the requirement of either NEMMCO or TNSPs to maintain inter-regional transfer limits at defined levels.

Noting the observations regarding the Code and the move towards competitive arrangements in NCAS, the following Code issues should be considered:

- Because the market can ascribe a value to link transfer capacity at the margin, augmentation of intra-regional network capacities should be by way of economic analysis (that includes the "do nothing" option.
- Responsibilities for voltage control services and for maintaining or enhancing inter-regional capacity should be clarified.
- In relation to potential changes to the arrangements associated with the procurement of reactive:
  - review the commercial incentives regarding reactive planning for TNSPs and DNSPs; and
  - review of the mandatory reactive requirements of generators in relation to the reactive provision.

To deal with the first matter we propose that the provision of ancillary services be removed from the TNSP regulated environment and placed within the competitive ancillary service environment proposed by this report. The effect of this is that procurement and dispatch of reactive would need to be considered commercially in relation to the alternatives, two important options being:

- the management of reactive consumption by the DBs and their end users; and
- alternative suppliers of reactive capability connected to the transmission network;

as well as the "do nothing" option if the spot trading benefits do not justify the additional network capability or if there are generation or load management alternatives to that capability (see next sub-section). To the extent that TNSP facilities turn out to be the most competitive option in particular cases, this proposal would change the basis on which the TNSP justifies the return it would receive on the voltage control facilities. We recognise that this would move but not change the more fundamental difficulties that arise from the interface between the regulated logic of the networks and the market logic in the energy-trading regime. Despite that, we believe the change would improve the ancillary service regime without significant additional downside.

The DBs have a nominal power factor obligation but no commercial incentives to achieve it or do better if it is cost effective to do so. We therefore also propose that the DBs become active participants in any pricing or market regime for reactive power or capability that is established. This would strengthen the rather weak interface the currently exists between the DNSPs and TNSPs in relation to voltage control.

The matter in the second dot point above should be considered in the "who pays and how much" phase of the current project.

4.5.3 Voltage Control - Contingency

Overview

The voltage control-contingency service falls within the framework described earlier in this section – namely, that the service tends to add to the secure capability of the network, particularly certain inter-regional transfers. As a result, there is scope for two-way trade between the associated reactive capability and energy market participants, or parties acting on their behalf. This is supported by the diversity of potential reactive sources and consumers. Further, the form of the generic constraints suggests that, while sources in different locations have a differential impact on link capability, that differential impact can be quantified and brought to a common base for trading purposes by appropriate definition of generic constraints in the SPD, as discussed earlier in this section.

As a practical matter, active trade in this service would tend to be restricted to times of heavy load in the year, when these constraints are most likely to bind. A corollary would be that continuous reactive power would also be priced and traded at such times (but not at other times, when different arrangements would need to apply).

During the transition, arrangements similar to those used at present would apply, but steps would be taken to refine the terms of the generic (security) constraints, reform the institutional basis for ancillary service provision by the TNSPs and TNSPs and introduce spot payments based on the generic constraint shadow pricing logic.

Light on the Hill

- NEMMCO’s role would be to define and manage the security constraints that define the terms of trade in this service.
- NEMMCO would dispatch, price and settle the provision of reactive capability and re-active consumption through the generic constraint logic in the SPD process as described earlier in this section.
- Long term procurement would be organised through two-way trade between reactive providers, consumers and parties who have an entrepreneurial interest in maintaining secure network capability for the purposes of energy trade.
- Static and dynamic reactive capability would need to be distinguished as separate products. Continuous reactive at peak times would also be priced under this arrangement as the constraints are likely to be defined in terms of total capability, which will include continuous provision.

Transition

- Subject to the progressive changes outlined below, continue with the current arrangements for procurement, pricing and dispatch:
  - contracts (hedging/procurement) between generators and TNSP (or NEMMCO depending on the clarification of responsibilities) for reactive reserve;

- for reactive generation up to the level that may be specified in connection agreements, no cost associated with reactive reserve;
- for reactive generation above this level, negotiated contracts that specify availability and enablement components;
- a compensation to be payable also if generating plant needs to be backed off to provide the service. Although testing of an AC load flow nodal pricing model that would price reactive energy in the context of energy spot trading is proposed, the co-dispatch of generator reactive capability with the energy spot market may not be warranted or feasible in the transitional phase;

- Pending ancillary service arrangements, implement the following Code changes:
  - TNSP ancillary service plant (and reactive plant in particular) should be removed from the TNSP regulated asset base and justified and managed within the ancillary services regime;
  - DNSP reactive consumption to be priced and charged according to the arrangements established, with existing power factor obligations regarded as a contract base;
  - the approach to the provision of reactive through connection agreements to be determined in the "who pays and how much phase of this project.
- Implement the formal procedures for generic constraint review and shadow pricing as recommended earlier in this section.
- Implement payments and charges for reactive capability based on shadow prices from the relevant generic constraints in the SPD process, and specifically for reactive consumption by DBs.
- Depending on assessments of feasibility or progress with the introduction of arrangements for entrepreneurial network development, introduce two way market arrangements as proposed for the light on the hill.

4.5.4 Voltage Control - Continuous

Overview

The proposals for Voltage Control - Contingency are relevant to the Continuous service; specifically:

- The proposed changes in relation to charging or paying DBs for reactive, removing reactive facilities from the TNSP regulated rate base and reviewing the basis for the provision of reactive under generator connection agreements.
- The proposed arrangements for shadow pricing and establishing trading arrangements would apply to the continuous service also at times when contingency constraints are

binding. Other arrangements would be needed to deal with the continuous voltage requirement for the rest (and majority) of the time.

Further progress on this service requires more study. There is at present no clear basis for valuing or trading of continuous reactive power. It is likely that progress will include replacing of the current zonal SPD model (that excludes reactive power and voltage considerations) with a nodal SPD model based on AC load flow analysis.

Light on the Hill

Ultimate arrangements are proposed to include the following.

- Shadow pricing of continuous reactive provision and consumption jointly with the Voltage-Contingency service as described for that service.

- Some form of pricing or trading arrangement based on studies carried out using AC loadflow analysis that would treat continuous reactive provision and consumption on an equal basis, and recognising the potential for providers to exercise market power.

Transition

- Contracts between generators and TNSPs / NEMMCO depending on the clarification of responsibilities in the "who pays and how much" phase for reactive generation.

- For reactive generation up to the level currently specified in connection agreements, costs to be limited to a recognition of usage costs.

- For reactive above this level, negotiated contracts that specify enablement and usage components.

4.5.5 Stability

Overview

The Stability ancillary service refers to the ability to maintain dynamic and transient stability of the national electricity system following a credible contingency, by equipment located at generating units, within transmission and at customer premises. Examples of equipment are generator AVRs, high-speed control, SVCs and protection schemes.

Stability is solely a system security issue, although like voltage, enhanced stability provides for enhanced transmission link transfer capability, and inter-regional transfer capability in particular. Consequently, stability also displays a security / link capability duality.

The current arrangements for stability is via a service called Rapid Generator Unit Unloading (RGUU) and provides for the rapid unloading of certain brown coal generator units in the Latrobe Valley should the interconnection to South Australia be "cut" under conditions of high power flows to South Australia. The service ensures that over frequency oscillations in Victoria are damped sufficiently in accordance with defined standards. The removal of this scheme would constrain power flows to South Australia under certain power system conditions.

The characteristics of this service indicate that there is limited scope for short-term competition:

- the products are non-standard, although there is the potential for products to substitute;
- information provision relies on detailed studies (usually by TNSPs or NEMMCO) on potential schemes that can enhance stability; and
- there would be limited providers of specialised stability schemes.

While this does not entirely rule out the possibility of entrepreneurial provision, the limited application and cost of the service at present suggests that this would not be a high priority. Nevertheless, the service should be subject to the same improvement in shadow pricing and transparency that has been recommended for the NCAS group as a whole.

Light on the Hill

- Implement the formal procedures for generic constraint review and shadow pricing as recommended earlier in this section.
- Depending on assessments of feasibility or progress with the introduction of arrangements for entrepreneurial network development, introduce two-way as proposed for the light on the hill. In the case of Stability Control such arrangements are likely to involve negotiation based on long term contracts rather than short term / spot trading.

Transition

- Negotiated contracts as the most appropriate arrangement for procuring stability services for the foreseeable future. The arrangements would require NEMMCO to provide information on potential stability schemes and the service that they would provide. This would need to be in the Statement of Opportunities.

4.5.6 Network Loading Control

Overview

In many respects Network Loading Contingency Control is similar to the Stability ancillary service, in that the service comprises schemes (normally generation or demand adjustment) to increase pre-contingency network capability. However there are several significant differences:

- the requirement or potential opportunities for Network Loading Contingency Control is geographic (ie. concerned with particular network elements); and
- value depends dispatch patterns and regional /spatial load distribution.

Network Loading Contingency Control acts to enhance the operational capacity of the network by providing for higher pre-contingency link flows than would otherwise be the case. These enhanced link flows could be associated with intra-regional network capacity or interregional link capability.

In most respects the scope and justification for moving toward market arrangements in this service are similar to stability services i.e. such a move is not of the highest priority. Nevertheless, the general approach to NCAS contingency-based services would apply.

Light on the Hill

- Implement the formal procedures for generic constraint review and shadow pricing as recommended earlier in this section.

- Depending on assessments of feasibility or progress with the introduction of arrangements for entrepreneurial network development, introduce two way arrangements as proposed for the light on the hill. In the case of Network Loading Control such arrangements are likely to involve negotiation based on long term contracts rather than short-term / spot trading.

Transition

- Negotiated contracts as the most appropriate arrangement for procuring stability services for the foreseeable future. The arrangements would require NEMMCO to provide information on potential schemes and the service that they would provide. This would need to be in the Statement of Opportunities.

4.5.7 Spot Market Trading Benefits

Overview

The main theme in the consideration of NCAS in this section, at least as far as options for the light on the hill are concerned, has been the relationship between the provision of NCAS and the benefits of trade that can be achieved in the energy spot market. The theme has been improving the efficiency of NCAS provision in relation to the energy spot market. However, this might involve in some cases a modest loss in trading benefits with a larger offsetting reduction in NCAS cost, although in the long run we would expect the change to be in the direction of enhanced spot trading benefits.

We take this service to mean the exploitation of possibilities that might exist to enhance spot trading in ways other than the provision of concrete technical facilities, such as the provision of reactive power capability or stability services.

Another way of enhancing spot market trading benefits is to improve the system pricing and dispatch (SPD) methodology. This could be done in two ways that we will consider in turn:

- removing unnecessary constraints in the SPD model that produces the dispatch outcome; and

- replacing the current the SPD model with a model that more accurately represents the underlying network and the security constraints that are applied to its operation.

The way that generic constraints are applied in the SPD process has been discussed at length in this section and the major recommendations for the light on the hill relate to improved outcomes that could be achieved by relaxing these constraints in various ways. A review of many of these constraints suggests that some potential benefits of trade are not being realised because load and dispatch patterns are in many cases taken as fixed where they are clearly variable. The reason this has done has an historical background as outlined in Section 2 but it should be reviewed.

One well-known example in the past has been the case where some generation from Southern Hydro in Victoria could relax constraints on inter-regional transfers from the north by a factor of several times its own output. Under the current arrangements this adjustment and corresponding benefits cannot be recognised, because the variable that affects this limit (Southern Hydro's generation) is fixed in the model *before* the optimisation takes place. It is a relatively simple matter to remove this constraint[89]. The logic is no different to that described for other NCAS; it is simpler in that it involves only real energy that is already in the spot market.

Appendix 4 contains several worked examples of what would be achieved by relaxing this constraint in the example involving Southern Hydro. The data is illustrative only. In all cases there is a robust improvement in total trading benefits from removing the constraints, as would be expected. The examples also show that the change would affect prices in different regions in different ways depending on the circumstances, as would be expected for any change that affects trade.

A second way to improve trading benefits would be to replace the current simplified network model in the SPD with a more accurate one, probably based on an AC loadflow methodology, that can deal with reactive power and voltages. This possibility is been considered in the context of the NECA Transmission and Distribution Pricing Review. We see benefits in developing such a model sooner rather than later and running it in parallel with the existing SPD model for testing purposes. Without this, none of the questions surrounding the merits of such an approach can be answered on any basis of hard facts.

Light on the Hill

- Implement the formal procedures for generic constraint review and shadow pricing as recommended earlier in this section.

- Using the existing bid arrangements for dispatchable plant, relax the dispatch variables in all constraints where they appear, thereby capturing improved spot trading benefits. Settlement should report each constraint transaction.

[89] By moving the dispatch level that is fixed on the RHS of the constraint to a variable on the LHS, as outlined earlier in this section.

- Replace the current transportation model in the SPD with a full AC loadflow model This will more accurately model network relationships including the management of voltages and associated reactive power and thereby:
  - improve the benefits of trade; and
  - improve prospects for pricing and managing the continuous voltage control service.

Transition

- Consider a trial of relaxing dispatch variables in one of the more significant generic constraints involving them.
- Implement and test a trial AC loadflow nodal pricing model running parallel with the current SPD engine.

5 System Restart Ancillary Service

5.1 Overview

The System Restart Ancillary Service stands apart from FCAS and NCAS in that it would be invoked under abnormal "system black" conditions. Footnotes in the Framework document query where this boundary might lie in fact, as recovery from a "system black" will lead to a point where the market can re-recommence functioning if suspended. This boundary will have both a geographic as well as a time dimension.

5.2 Review of Framework Classification Matrix

5.2.1 Cause of the Requirement

The Framework Classification Matrix lists the cause of the requirement as "partial or total system black". Within that we can distinguish a range of situations:

- system black over the whole inter-connected system;
- system black over a single NEM market region;
- system black within a major load centre of a region e.g. CBD of a major city; and
- system black over a smaller geographic area.

The cause of a system black might be a cascading failure that nevertheless allows relatively prompt reconnection (hours rather than days, weeks or months), or it might be much longer term, such as the multiple cable failures that occurred in Auckland in 1998. The last two cases could be caused by regional or local network failures.

5.2.2 Driver for Quantity of Requirement

The Framework lists the driver for the quantity of requirement as the need for prompt system restart on economic, political and public safety grounds. There are also geographic dimensions to the requirement, as discussed later.

5.2.3 Technical Options for Meeting Requirement

The Framework lists generators, including provision for switching load blocks and network capability. The generators must be capable of starting without the need for mains electrical power. Diesel and hydro generators with independent electrical power for auxiliaries would be examples of providers, including moveable resources. Coal plants are unsuitable because of their requirement for mains-based auxiliary power.

5.2.4 Measurements of provision and cause

The Framework lists SCADA for delivery and testing to ensure availability when needed. As noted later, a good way to ensure reasonable reliability on start-up at modest cost is to use the facility periodically for other purposes.

5.2.5 Geographical Considerations and Potential for Competition

Geographical location is a major issue for system restart facilities. To reduce the costs associated with system failures, it would be desirable to have some local generation backup in any net consumption area to ensure prompt provision of at least a basic supply of power in the event of local network failure. On a broader geographic scale, some regionalisation of system restart facilities is also desirable to deal with the possibility of inter-regional link failure.

5.3 Discussion

Indications from NEMMCO to date are that this service costs around 10% of the expected ancillary services bill, or around $10 million each year excluding Queensland. Being seldom used, the ongoing costs to be covered tend to be static, imposing less of a risk management problem for the paying parties than the more volatile costs of some other services.

Key features of this service are:

- the range of total or partial system black conditions that need to be addressed, especially in terms of geographic location;
- the need to balance the cost of provision against the expected cost and delays of recovery from the system black condition; and
- for this reason, the desirability of geographic dispersion of service providers, with some focus on location close to strategic loads.

Centralised contracting with the geographic diversity of providers that would be necessary to provide maximum flexibility in the particular circumstances would be expensive and inequitable. On the other hand, to have no plans for fast, localised support beyond what might be contracted long-term and paid for long-term would be imprudent.

For these reasons a mixed strategy could provide the best balance of service and cost. A "basic service" supported by long-term contracts would provide assurance that system re-start can be achieved within a reasonable time. This could be supplemented by more locally based resources whose prime role would be to ameliorate the costs to loads of a system black condition. This "supplementary service" could operate at two levels:

- procurement of resources at the time of need from those whose availability will have been demonstrated in other duties; and
- procurement on some longer-term basis.

Providers of such a supplementary service could be standby generators within the distribution network, especially those in or near the CBDs of the major cities, or even portable resources that could be moved quickly by road or rail to a localised area of need. As noted earlier in this report, loads and standby generators can provide a range of ancillary services for both the distribution and transmission systems. When these facilities are fully developed and used to their potential, they would run often enough (several times a year) to provide some confidence as to their serviceability when required. They could usefully supplement other providers by offering reasonably fast relief for essential services in localised areas.

We note that procedures to use distributed stand-by generation to support various aspects of NEM operations remain under-developed. There appear to be ongoing environmental concerns that need to be dealt with, but the key problem has been a lack of incentive to press such facilities into service[90]. Until confidence develops in such facilities it would be premature to rely on them.

At the other end of the spectrum, individual loads, coalitions of loads or even jurisdictions might come to a view that they would be prepared to pay for the ongoing costs of facilities that could re-start them sooner than might otherwise be possible. In such cases NEMMCO could take account of the resources they procure, or could procure such resources on their behalf and charge them accordingly. These parties would have priority use of facilities so procured in the event of a system black condition. Compensation arrangements would need to be in place should they be commandeered by jurisdictions at the time.

5.4 Proposals

5.4.1 Short-term

For the short term we propose little change to recent practice, except to note that a longer-term contractual arrangement might be more cost-effective. However, bearing in mind proposals for the light on the hill, the immediate contract term from July 1999 should be for a limited period.

5.4.2 Light on the Hill

For the light on the hill we propose a review oversighted by the NECA Reliability Panel, and subsequent implementation of a long-term strategy for the provision of system re-start services, taking into account:

- the need to maintain a basic set of resources to ensure the system can be re-started with a reasonable time, recognising that such resources might be more cheaply procured with longer term contracts, and may in part be available through arrangements that the current NECA capacity payments review might recommend;
- the desirability of acquiring supplementary resources on a competitive basis to meet immediate needs, including rapid relief for the worst impacts of localised or widespread system black conditions;
- the various options, especially those embedded within the distribution network, that could be developed over the next three years (say) and called upon at short notice; and

[90] Noting that "service" in this case largely means maintaining availability. Actual operation would remain an unusual event, at least for use in the system restart duty.

- the desirability of allowing individual or coalitions of interest to gain priority access to re-start facilities, if they procure such resources themselves or pay all the costs of procurement by NEMMCO.

We also propose a broad strategy to develop embedded load management and generation resources that can support a wide range of frequency-related, distribution and transmission ancillary service requirements, as well as system restart. This is detailed further in Section 6.

6 Light on the Hill Proposals

6.1 Overview

In this section we set out in summary form the proposed light on the hill proposals that emerge from the previous analysis. Although many implementation details require more investigation and testing, we believe they are well within the reach of current technology and consistent with the objectives of the NEM and the proposed new ancillary services regime.

For conciseness, the proposed light on the hill arrangements are presented here with minimal supporting discussion. Fuller discussion can be found in the previous Sections of the report and also in Sections 7 and 8, where approaches to the specific services defined in the Framework are outlined.

6.2 Categorisation

Ancillary services in the NEM should be grouped into three categories, each having a common management logic:

- Frequency Control Ancillary Services (FCAS);
- Network Control Ancillary Services (NCAS);
- System Restart Ancillary Service (SRAS).

6.3 Objectives for Ancillary Service Arrangements

The ancillary service regime in the NEM should have the following long-term objectives:

- NEMMCO should not procure or trade directly in ancillary services (with the possible exception of some SRAS). Its role should be to implement security standards and to manage integrated trade in spot energy and ancillary services that achieves those standards efficiently, in a similar way as it currently does for the energy spot market;
- The costs and financial uncertainties of ancillary services should be reduced substantially from current levels by introducing two way markets in both and FCAS and NCAS, and promoting short-term competitive supply of some SRAS;
- Maximisation of demand-side participation, by recognising the multiple services that load shedding, load modulation, local generation and local reactive power management can provide both within the distribution network and to the larger system, in all ancillary service categories.

These objectives may not all be achieved fully for a variety of reasons. However, we consider that they can be substantially achieved in most cases, and certainly for those ancillary services that are currently relatively large in cost.

6.4 FCAS

The central element of the light on the hill for FCAS is a ***market in short-term energy deviations*** to supplement the current half-hourly energy spot market. When fully developed, this market would encapsulate both the small deviation and, to a significant extent, the large deviation frequency management services as defined in the Framework.

- The ***participants*** in the market will be buyers and sellers in the energy spot market, including agents acting on behalf of end-users. However, in general there will be no direct correspondence between buyers and sellers in the energy spot market and buyers and sellers in the energy deviations market; at any given time, buyers in one market may be sellers in the other, and vice-versa.

- The ***tradeable product*** is *short-term deviations* or *increments* of energy production and consumption relative to half-hourly average energy production and consumption applied to the short interval.

- Facilities operating in the deviations market may be ***dispatched for use***:

  - through the central AGC; or

  - by independent action based on localised measurements in the case of non-(centrally) dispatchable facilities or dispatchable facilities that are considered suitable for self-dispatch in this market.

  A subset of facilities may be centrally enabled through the SPD process, based on bids, to provide NEMMCO with assurances as to capability.

- The ***market price*** is determined as *a price increment (positive or negative) relative to the energy spot market price* and set according to an algorithm designed to reward energy production and consumption *deviations* that drive the system towards a stable outcome. Parameters in the RTP price-setting formula would be set to produce the frequency response pattern that would meet a centrally-determined frequency standard. This pricing logic is called Real Time Pricing (RTP) and is closely integrated with the operations of NEMMCO's AGC and the SPD process of the energy spot market. The total price applying to short term energy production or consumption will be known at any instant.

- The price increment will apply to short-term deviations from a defined level of energy production or consumption based on energy market outcomes. As electrical energy production and consumption balance over any short time interval (after adjusting for losses) there will, in the simplest case at least, be balanced production and consumption of *deviation energy* at any instant, and settlement payments will tend to balance accordingly[91]. ***The proposed energy deviations market does not require an external injection of funding***.

[91] One possible implementation could produce a small settlement surplus in the same way as the energy market does.

- The RTP logic can be applied to both sides of the energy market and to non-dispatchable as well as dispatchable load and generation. This greatly broadens the scope for competition. Further, there should be parties on both sides of the proposed energy deviations market who would be willing to enter into ***bilateral hedging arrangements*** to manage their financial exposures to the deviations market. ***There would be centralised long-term procurement for this capability***.

- While existing FCAS product categories (or a modification of them), bid and settlement arrangements and registration of capability with NEMMCO could remain as a backstop, ***most of the value in FCAS trading will be in the energy deviations market***. Further, no such arbitrary distinctions will be drawn between different FCAS product categories in the energy deviations market.

- The turnover of the energy deviations market when fully developed should be very much smaller than current FCAS costs because of the potential breadth of participation, especially from the end-user sector.

6.5 NCAS

The central element of the light on the hill for NCAS is a set of ***two-way markets in services supporting secure network capability***. When fully developed, this market would encapsulate the voltage control services (although continuous voltage control requires special measures separate from these described below), the stability and network loading control services and enhanced spot trading as defined in the Framework.

- The ***participants*** in the market will be those who benefit from and influence ***secure network capability*** as defined and agreed in a robust public process established under the NEM; i.e:

  - Participants whose facilities or actions ***enhance secure network capability;***

  - Participants whose facilities or actions ***reduce secure network capability;***

  - Participants who have a ***commercial interest in secure network capability***.

  Facilities owned and operated by TNSPs should be removed from the regulated rate base and included in these arrangements. Demand-side capability should be explicitly recognised also, either by the pricing of relevant NCAS at market boundaries or by recognising the capability of facilities embedded in the distribution network to provide the service. Under current arrangements the only party that may actively seek to influence secure network capability through the procurement of ancillary services is NEMMCO. Parties who may have this interest in future would include ***entrepreneurial network service providers or parties originating inter or intra-regional hedges***.

- The ***tradeable products*** are *MW of network capability associated with a specific technical factor and contingency affecting network security, as expressed in a SPD generic constraint*. Generic constraints imposed on the energy spot market dispatch are intended to maintain secure network operations in the event of a contingency. In this context we note that a particular facility can effectively trade in several NCAS markets simultaneously; ***facilities in these markets essentially provide an insurance service***.

- ***Dispatch of capability*** is achieved though declaring availability and, as determined on a case by case basis for each type of NCAS, Market Participants making bids into each NCAS market through the energy spot market SPD process. ***Dispatch for use*** will normally be achieved though automatic systems activated in the event of a contingency.

- The ***market price*** for an NCAS capability to deal with a particular network contingency (or NCAS market as defined) is determined as *the shadow price of the corresponding generic constraint as determined in the energy spot market SPD process*. A particular facility can pay or receive the market price associated with more than one NCAS markets. The procedure for ***payment for usage*** requires further examination.

- In the event that entrepreneurial arrangements are developed for the origination of inter-regional hedges and network augmentation in the NEM, the task of ***procurement of NCAS will be organised by interested parties under contractual arrangements suitable to them***. In the event that no such development occurs, NEMMCO will continue to procure NCAS capability either by relying on short-term competitive bids or by contracts based on competitive tender, commercial negotiation or under mandatory code arrangements as may be appropriate in each case.

- In the energy spot market a balance between energy purchased and energy sold is a necessary physical outcome after making appropriate allowance for losses. On the other hand, trading in NCAS is based on imposing generic constraints on the energy market SPD process; NCAS directly influences energy trade through this mechanism. ***It follows that the definition of the generic constraints to be applied in the SPD process is a core component for the successful operation of such markets.*** Robust and public processes will run by NEMMCO and overseen by the Reliability Panel to review and determine these generic constraints.

- While some enhanced spot market trading is provided under these arrangements, and reactive power (for continuous voltage control) will be traded under constrained conditions (jointly with reactive power capability), further progress in these areas requires more study. ***It is likely that this will involve replacing of the current zonal SPD model (that excludes reactive power and voltage considerations) with a nodal SPD model based on AC load flow analysis. Such a SPD model would remove some remaining network anomalies and provide the basis for pricing and trading in voltage-related services including reactive power.***

6.6 SRAS

- The central element of the SRAS light on the hill is to recognise two services within this group:

  - a *basic service*, intended to ensure that the whole system or substantial parts of it can be re-started within a reasonable time; and

- a *supplementary service*, intended to ameliorate the costs to critical loads and other market participants of a system black condition, prior to the system being fully re-started.

- ***Procurement and pricing*** of the *basic service* would be by NEMMCO contracting long term following a competitive tender process.

- ***Procurement and pricing*** of the *supplementary service* would be either by the interested parties directly, by an organisation (such as a DB) acting on their behalf, or by NEMMCO following a request from a coalition indicating a willingness to pay.

- ***Dispatch*** of the basic service should be by NEMMCO, and the supplementary service by NEMMCO or DNSPs as appropriate in each circumstance, and noting the need for co-ordination.

7 Implementation and Transition Strategy

7.1 Overview

In this Section we consider an implementation strategy for more competitive arrangements for ancillary services building on the analysis and light on the hill outlined earlier. The focus here is on the broad strategy for the ancillary service groups we have identified (FCAS, NCAS and SRAS), as well as on some common themes that have emerged during the analysis. ***Sections 3,4 and 5 considers and recommends on each of the services defined in the Framework explicitly and in more detail, as we are required to do under the brief.***

7.2 Broad Priorities

The scope for introducing more competition through markets and the greatest immediate benefits are likely to be in FCAS. Therefore, the broad implementation priorities in chronological order are:

- Proceed with the necessary consultations and Code changes to support the changes outlined below.
- Implement spot markets in FCAS enablement as a top priority to meet the immediate requirements of the ACCC and to gain the benefits of further competition, as outlined below. This implementation be staged if there are significant IT issues in the development.
- Request that the Reliability Panel's role be enhanced to oversight the following tasks as a matter of priority, with NEMMCO and NSP technical support as appropriate, using open and robust public processes and recognising the fundamental role of the demand-side in the provision and consumption of all of these services:
  - review of frequency and time error standards;
  - review of the basis for the setting of specific generic constraints, with a priority on those constraints which have the greatest impact on spot trading; and
  - review of system restart strategies, noting the relationship between the facilities required to meet local needs and those required to meet the needs of the system as a whole.
- Pending the new ancillary service arrangements, implement the Code changes necessary to ensure that currently regulated network facilities, retailers, distributors and end users that participate in ancillary service provision and consumption are treated on an equal basis in relation to the provision of ancillary services.
- Investigate the following for implementation, taking into account the results of Reliability Panel deliberations:

- a redefinition of FCAS enablement product categories to remove technological biases current anomalies;
- adjustments to the SPD that would dynamically determine the requirement for the large frequency deviation FCAS based on the pattern of dispatch;
- an optional energy deviations market to supplement the spot markets in FCAS, this regime to be designed to allow participation by non-dispatchable loads as well as dispatchable plant;
- the trading of selected NCAS through the operations of generic constraints in the energy spot market SPD, focussing initially on the voltage-contingency service and on opportunities for enhanced spot trading involving existing energy bids and offers;
- enhanced spot trading and improved pricing and possible trading of the continuous voltage control services, through the development an operation in parallel with the SPD of a pricing model based on AC load-flow analysis.

We note that the light on the hill proposals for both FCAS and NCAS involve the establishment of two-way trading arrangements between causers and providers. Such arrangements are likely to be more amenable to bilateral hedging than central acquisition with cost pass-through to participants according to approximate causation rules.

There are additional recommendations that are more appropriately addressed in the “who pays and how much” stage of the project.

Specific recommendations relating to each group of the service Groups and other general issues are in the following sub-sections. Each service is then addressed in Section 8.

7.3 FCAS

This broad implementation strategy for FCAS is encapsulated in the following recommendations.

- The strategy for FCAS should be to reduce its cost by:
  - a review of the standards for frequency and time error control from an economic perspective, and especially with a view to widening the small frequency deviation standard to reduce the cost of meeting it;
  - shortening the bidding cycles for FCAS enablement and implementing a common clearing price for them (determined as the defined “supply price” for each FCAS product as defined in the SPD documentation) so that they operate in parallel with, and integrated with, the spot energy market; and
  - investigating during the ”who pays and how much” stage of this project the likely feasibility of an optional energy deviations market regime to supplement the proposed spot market in FCAS.

- The spot market for FCAS enablement should:
  - be based on current FCAS product categories unless early investigation shows that RTP is likely to be impractical, in which case other product categorisations should be investigated, along the lines discussed in Section 3 of this report;
  - be supported by an ongoing provider registration process with NEMMCO for each defined FCAS product;
  - generally, *not* require NEMMCO to enter into contracts) except for under-frequency load shedding should that prove necessary for FCAS;
  - clear at the common clearing price corresponding to the shadow price of the relevant FCAS product supply constraint in the SPD (i.e. the "supply price" as defined in the SPD documentation);
  - be implemented in a similar way for both the small deviation and large deviation services;
  - be subject to initial vesting contracts designed and apportioned according to procedures established in the "who pays and how much" stage of this project; and
  - operate in parallel with any component of these services that may be subject to mandatory Code requirements or connection agreements (to be reviewed in the "who pays and how much" stage of this project).
- The proposed energy deviations market should:
  - operate to supplement the spot "enablement" markets in FCAS described above with a market in FCAS usage;
  - be based on a time interval consistent with the short-term dynamics of the system as well as data availability, which will depend on the timeliness of SCADA data and the possibilities for local measurement;
  - be based on the concept of *incremental prices* applied to *incremental energy quantities or deviations* relative to energy spot market outcomes;
  - be designed to be consistent with AGC and other stable operational outcomes, but also able to be implemented at sites not under AGC control be referencing local frequency measurements and 5 minute SPD data;
  - support participation by parties or processes whose responses can only be measured on a sampled basis rather than in real time;
  - be implemented as an option in the first instance, to recognise that some Participants may not feel able to manage themselves under such a regime; and
  - be investigated in concept as part of the "who pays and how much" stage of the ancillary services project.

7.4 NCAS

The NCAS group is defined to have the common characteristic *of increasing secure operating limits* over the network. In relation to this, we note the following:

- The definition of these network security constraints is not a precise science. It requires engineering analyses, assessments of operational risk and consideration of a range of measures that might ameliorate the effect of contingent events such as line outages;
- Current operating limits were determined in a closed process by previous utilities, so that there is no basis for believing that they currently define limits that reflect the priorities of Market Participants in the current market-trading regime. Specifically, there is some evidence that the limits as currently defined do not reflect the potential for demand-side response;
- Once these operational constraints are defined, there is an identifiable trade-off between the provision of these services and the ability for trade to occur over the network; further this trade-off-can be quantified in shadow price terms through the outcome of the SPD process. This trade-off supports the possibility of two-way markets in NCAS, *provided that the trading parties agree that the defined security constraints represent a fair and robust basis for trade in NCAS*.

Given that these steps have been undertaken which we recommend as a priority, further consideration then needs to be given to the possibility of establishing markets in NCAS, or at least in explicitly valuing them. This leads to the following recommendations:

- In the short term, and on an annual basis, NCAS services should be provided through a competitive tender process or negotiated (or mandated) contracts as at present. This approach recognises the higher priority of FCAS in terms of potential efficiency gains, and the additional work that needs to be done to provide a foundation for more competitive NCAS provision, as outlined below.
- Further consideration of markets in NCAS should be preceded by a review of the basis for and structure of the currently defined security constraints applied in the SPD process. As significant financial trade-offs are involved, this review should carried out by robust, public processes overviewed by the Reliability Panel. Such a review should recognise the potential for demand-side participation in the provision and consumption of NCAS.
- NEMMCO should extract and publish the pattern of shadow prices from the SPD process associated with each (or at least the most significant) generic constraints used in the SPD process, as well as the corresponding financial rents associated with each constraint. It should also publish the marginal physical and financial impact of each activity that affects each constraint, including demand-side activity.
- NEMMCO should take account of this shadow price information when determining the appropriate quantum to acquire in its contract tenders and negotiations.

- After investigation on a case by case basis and if feasible and desirable given market power and materiality considerations, a spot market should be established, integrated with the spot energy market, as outlined in the sections below, probably staged as follows:
  - paying and/or charging NCAS providers on the basis of the shadow prices associated with each binding generic constraint in the SPD, and on the basis of declared (and confirmed) availability; or
  - centrally dispatching such services through the energy market SPD process, based on bids and offers for service consumption and provision;
- If a spot market in a particular service is not feasible or desirable, procurement should continue to be by competitive tender and dispatched manually (i.e. by notifying availability to NEMMCO and including it as a given in the SPD generic constraint logic.
- Regardless of whether a service is procured by competitive tender or through a spot market, NEMMCO should stand aside to allow other parties to contract with NCAS providers should the development of the network transmission pricing and investment regime support such entrepreneurial activity in future.
- To support later development of an NCAS trading regime, and in particular arrangements for continuous voltage control and enhanced spot trading:
  - implement the Code changes necessary to ensure that currently regulated network facilities, retailers, distributors and end users that participate in ancillary service provision and consumption are treated on the same basis as other Participants;
  - develop an SPD model based on AC load-flow analysis and operate it in parallel with the current SPD for testing and evaluation purposes.

7.5 SRAS

- Current arrangements should be unchanged during the transition.
- The development of the re-start strategy for the light on the hill should be ***co-ordinated by NEMMCO in consultation with TNSPs and DNSPs, under the oversight of the Reliability Panel*** and subject to a robust public process.

7.6 Retail Co-ordination

In earlier section of this report we listed the range of duties that a load shedding, load reduction, local generation or reactive power management facility embedded within the distribution network could perform. Amalgamating this list, these were:

- managing network contingencies *within* distribution areas e.g. shedding load for a relatively few hours each year to defer major investment in further distribution wires[92];
- managing spot market purchase costs through the controlled shedding of domestic hot water and other loads by retailers (or distributors on their behalf);
- managing the risks associated with high loads and high prices in the spot energy market;
- managing large frequency deviations as proposed in the Framework, with potential for managing small deviations as well;
- managing contingencies affecting voltage, as nominated in the Framework;
- managing the demand for continuous reactive power, as nominated in the Framework;
- stability control (high speed) as nominated in the Framework;
- network loading control, as nominated in the Framework;
- enhancements to system restart capability, as discussed later in this report; and
- generally, to allow the possibility of further network constraints to be relaxed following more detailed consideration of them by the Reliability Panel.

This rather long list is of great interest because many of these functions are not mutually exclusive; that is the same facility can simultaneously provide many services without mutual interference. Further, the previous monopoly utilities did little to promote the demand-side, and this limited demand-side development is still evident at many points in the NEM. Examples are the supply-side orientation of the current FCAS arrangements and the frequent lack of recognition of the demand-side in the formulation of generic constraints that implement limits to network capability. Lack of demand-side development is also recognised as a key issue for NECA's current review of capacity remuneration in the NEM.

The central role of the demand-side at the "top end" of the energy market and as a potential provider of a wide range of ancillary services, as well as the ability of such facilities to serve multiple purposes, needs to be formally recognised and acted upon. Indeed, recognising and remunerating this wide-ranging utility will be a prime factor in the development of these facilities.

While it might be argued that the demand-side should be left to develop naturally at its own pace, there are some requirements that must be met:

- All ancillary services should be defined in ways that recognise the potential of the demand-side to contribute. *Examples* relating to this brief include:

[92] The current proposal by Transgrid and Sydney Electricity concerning the augmentation of supply to the Sydney CBD is a possible example.

- FCAS pricing and charging that recognises and rewards the contribution of the demand-side in providing load relief, in order to encourage greater load sensitivity;
- definition of generic constraints that recognises the influence of the demand-side, for example, through the consumption of reactive power; and
- recognition and accommodation of the possible overheads in measuring individual demands-side ancillary service provision (suggesting that survey data might also be used);

- Potential conflicts and diluted incentives within the regulated network businesses need to be addressed. Examples include:
    - the perceived conflict between the provision by NSPs of ancillary service facilities within the regulated rate base (e.g. reactive equipment owned by TNSPs) that might otherwise be more cheaply provided from other sources;
    - the perceived conflict between the provision of additional regulated wires assets that might otherwise be cost-effectively deferred with some demand-side load shedding or local generation facilities;
- Accountabilities for the management of some ancillary services within the distribution system need to be defined or clarified. Such accountabilities could rest with:
    - retailers;
    - distributors; and/or
    - independent and entrepreneurial load management entities.

    These options should be reviewed in the "who pays and how much" stage of the ancillary services project.

7.7 Role of the Reliability Panel

The Reliability Panel has a current accountability for setting frequency standards. TNSPs have defined secure network secure operating limits in the past and, to our knowledge, there are no immediate plans to change this practice even though NEMMCO has the taken over the operational responsibility for the system. System restart accountabilities lie with NEMMCO but local reliability remains a jurisdictional issue even though the same facilities will have utility at different levels.

The setting of secure operating limits and system restart strategies have strong commercial political overtones that apply not just at the jurisdictional level but to the market as a whole. For this reason we recommend that the NECA Reliability Panel's be requested to oversight the following tasks through open and robust and public processes:

- Noting the proposed review on frequency standards, this (or another review) should include the form of frequency standards and the corresponding FCAS requirements necessary;
- Review of the basis for the setting of specific generic constraints, with a priority on those constraints which have the greatest impact on spot trading[93];
- Review of system restart strategies, noting the relationship between the facilities required to meet local needs and those required to meet needs at a higher level.

The task should be carried out be NEMMCO with input from TNSPS and DNSPs retailers and other interested parties as required. Generic constraints could be dealt with by the Inter-regional Planning Committee established under the Code.

7.8 Code Changes

The following Code changes will be required to implement the recommendations of this report:

- Define the new elements of the new ancillary services regime:
    - rules for the spot FCAS markets;
    - rules for ancillary service payment (to be determined);
    - later, and if implemented, rules for Real Time Pricing and adjustment to the energy market SPD process; and
    - later, and if implemented, rules for enhanced spot trading involving NCAS.
- Pending ancillary service arrangements, remove TNSP ancillary service facilities from the regulated rate base.
- Pending ancillary service arrangements, remove mandatory provision clauses.
- Clarify the interface between distributors and retailers and the NEM ancillary services regime (for FCAS and reactive in particular, to be considered in the "who pays and how much" stage of the project).
- Define the objectives of the light on the hill proposals, noting the steps and milestones to be met on the way.
- Define the spot markets in FCAS enablement in terms sufficient to allow early implementation.

[93] This is consistent with the cost benefit trade off analysis currently being undertaken by NECA.

7.9 Issues Deferred

A number of matters have been deferred for later consideration in the "who pays and how much" brief. These include:

- *Allocation of ancillary service costs between Market Participants.*
- *Mandatory requirements*: this report has taken the view that services that may be mandated under the Code or connection agreements can operate alongside competitively acquired resources. Thus the issue of mandatory provision is largely a matter of "who pays and how much".
- *Self provision*: Following some elements of the US model, some services (e.g. FCAS) might be allocated by imposing an obligation to bring some determined share of the physical requirement to the system operator for dispatch rather than imposing the same share of the centrally incurred cost. Although this does impact on the approach to procurement, we have taken this to be a "who pays and how much" issue.
- *Accountabilities of retailers, distributor and end users*. Retailers, end users and distributors together can both impose a significant ancillary service burden on the system as well as play a major role in ancillary service provision. The terms of the current brief highlighted such demand-side interactions and opportunities and we have identified them in this report. Nevertheless, it is not in every case clear where the accountabilities should lie in the first instance. More detailed consideration of this issue has been deferred to the "who pays and how much" study.
- *Vesting contracts during transition to spot FCAS markets.*

7.10 Implementation Sequencing

The broad implementation priorities in chronological order are:

1. Proceed with consultations and Code changes to support the changes outlined below.
2. Implement spot markets in FCAS enablement as a top priority to meet the immediate requirements of the ACCC and to gain the benefits of further competition.
3. Enhance the Reliability Panel's role to oversight the following tasks, using open and robust public processes and recognising the fundamental role of the demand-side in the provision and consumption of all of these services:
   - A review of frequency and time error standards;
   - Review of the basis for the setting of specific generic constraints, with a priority on those constraints which have the greatest impact on spot trading;
   - Review of system restart strategies, noting the relationship between the facilities required to meet local needs and those required to meet needs at a higher level;

4. Implement Code changes to ensure that currently regulated network facilities, retailers, distributors and end users that participate in ancillary service provision and consumption are treated on a non-discriminatory basis in relation to the provision of ancillary services.

5. Investigate the following for implementation in the longer term, taking into account the results of Reliability Panel deliberations:

   - A redefinition of FCAS enablement product categories to remove technological biases current anomalies;

   - Adjustments to the SPD that would dynamically determine the requirement for the large frequency deviation FCAS based on the pattern of dispatch;

   - An optional energy deviations market to supplement the spot market in FCAS, to allow participation by non-dispatchable loads as well as dispatchable plant;

   - The trading of selected NCAS through the operations of generic constraints in the energy spot market SPD, focussing initially on the voltage-contingency service and on opportunities for enhanced spot trading involving existing energy bids and offers; and

   - Enhanced spot trading and improved pricing and possible trading of the continuous voltage control services, through the development an operation in parallel with the SPD of a pricing model based on AC load-flow analysis.

8 References

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