



Oakley Greenwood

Wholesale electricity generation market review



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1. Executive summary

The Northern Territory (Territory) Government is seeking to increase the opportunity for competitive forces to influence the investment in and operation of the electricity supply industry in the Territory. To this end Government has determined to introduce competitive market mechanisms into the sector and to structurally separate the incumbent vertically integrated state owned utility, Power and Water Corporation (PWC).

Structural reform will include disaggregation to create separate stand-alone government owned corporations for electricity retail and generation.

Government has also provided a reference to the Utilities Commission (Commission) seeking a review and related recommendations for the design of competitive arrangements for wholesale generation.

Oakley Greenwood Pty Ltd has been appointed to undertake the review. This report presents Oakley Greenwood's findings and recommendations. The substantive findings and recommendations are similar to those in a draft report published by the Commission in December 2013. However, this final report includes additional discussion of the reasoning for recommendations, particularly around issues raised in submissions to the draft report. The Commission intends to publish its formal response to Government in parallel with this report and we understand will address each of the points raised in submissions in detail.

Principal findings and recommendations

- The most appropriate form of competitive mechanism for a Northern Territory Electricity Market (NTEM), accounting for the Government's objectives and local circumstances, is a two-part market comprising:
 - Forward contracting for capacity and reserve; and
 - A relatively simple cost-based system-wide economic dispatch of energy in real time from which a single marginal clearing price for energy is developed;
- The proposed functional separation of generation from networks and the system control function is strongly supported, however, the current gas contracting activities within PWC should also be separated;
- The National Electricity Rules (NER) of the National Electricity Market (NEM) that operates in eastern and southern states should be the template for the rules of NTEM in the longer term;
- A transition path to longer term rules based on minor modifications to existing Codes operating in the Northern Territory would allow earlier and less costly implementation of the proposed trading arrangements if appropriate; and
- Day to day processes currently used between PWC Generation, PWC System Controller, PWC Network and PWC Gas are broadly consistent with the processes needed to implement the proposed energy trading arrangements and can be used as the basis for the equivalent processes in the NTEM. However, they will need to be made more rigorous and transparent in order to function as part of a robust market.

Rationale

The objectives established by governments, as policy makers for the industry, have a major impact on the design of competitive electricity markets. The objectives established for a competitive generation market in the Territory aim to create incentives for third party new entrants in both generation and retailing and for operational efficiency. These objectives preclude use of simpler more centrally managed arrangements, for example arrangements which presume on-going contract relationships between specific generation and retailing entities (or large customers) or only provide for generators to contract with the central agency.

In general, a well functioning market will produce an efficient level of investment and total charges to customers that recover the cost of investment and provide a competitive profit. If a market is over-supplied returns will be low and conversely if the market is undersupplied returns will be high. In most market designs some part of the payment to generators and charge to customers is based on a price determined from short term dispatch at different times of day. This price creates incentives for efficient dispatch and consumption. In order to reflect the costs involved in providing little used reserve the price in short term dispatch must rise above the short term supply-side cost or be supplemented by an additional payment, often called a capacity payment. A key objective of both arrangements is to create incentives for an efficient level of investment.

Electricity markets based on physical supply contracts between generators and wholesale customers, such as the Western Australian Wholesale Electricity Market (WA WEM), generally have a two part payment regime with a capacity payment and a real time market for dispatch at a price derived from short run costs of generation. Markets that involve payments based entirely on dispatched energy (energy-only markets such as the NEM), rely on market prices rising above short run supply costs to create incentives for investment as well as efficient dispatch. Participants in markets with a single price generally enter (financial) contracts between themselves outside the formal market. These contracts may create the equivalent a separate payment.

The choice of a single integrated design or separate mechanism leads to significant differences in the allocation and management of commercial risk and in the potential for market power to be exercised.

Our conclusion is that given the size and nature of the electricity systems in the Northern Territory, for the foreseeable future, a separate formal mechanism should be included within the market rules. This approach can also be viewed as institutionalising the type of voluntary arrangements that typically emerge in larger energy-only markets. The particular mechanism we are proposing, termed the Reliability Assurance Mechanism (RAM) uses financial instruments which, at an appropriate time, could be retired and the market transition to the same approach as the NEM. This transition would be far harder if the arrangements were based on payments for physical capacity. The concept of the RAM blends the assurance of contracting for capacity used in the WA WEM and established financial principles of the NEM. Final details of the mechanism's design for application in the Northern Territory market will need to be completed during detailed development of market rules.

A new role would be required to administer the RAM and require tenders for capacity to satisfy a robust and economically justified generation reliability standard. Existing generation and potential new entrants will be entitled to respond. All market designs that involve a separate payment related to capacity require a calculation of the amount of capacity needed to support the local reliability standard and some form of tender or auction process, accordingly the main difference between markets of this type is the form of contract. It is also important to note that the level of capacity that will be supported by an efficient capacity mechanism is the level needed to meet the local reliability standard. Accordingly, the RAM will have the capability to influence both new investment and where appropriate dis-investment, or retirement, and withdrawal of capacity.

Alternative designs are available that involve mandatory levels of contracting between the generation and retail sides of the market, different approaches to awarding payments for capacity or limited contracting to only a central agency (a single buyer). These designs were considered but not adopted. While each has merits, in different ways they compromise objectives for either independent third party participation, are incompatible with existing policy on customer choice (retail contestability) or require more extensive bespoke market rules and therefore increase rather than lower barriers to participation from existing Australian participants in other markets.

In respect of the day to day real time market, a number of characteristics of the electricity supply industry in the Territory allow for a relatively simple, and therefore less costly, market design than is the case elsewhere. In particular:

- The relatively stable weather at a given time of year leads to relatively predictable total customer demand - unlike in other states where volatile weather has a significant impact on preparation and positioning for real time trading;
- The dominance of gas as the fuel for power generation and generator technologies that can be started in no more than a matter of hours - unlike large coal fired boiler plant; and
- The flexibility and lack of penalty for changing gas requirements within a day - unlike other locations where variations from day-ahead nomination of required volumes attracts penalties.

Together these characteristics obviate the need for the day-ahead markets or processes in addition to the real time market seen elsewhere and also facilitate self-commitment decisions in relation to the starting and stopping of generation units (which are currently made by PWC Generation and therefore will not need to change).

On balance we also recommend that dispatch be based on demonstrable generator costs for dispatch.

Together these characteristics suggest that the market price may sit in a much narrower band than is seen in other markets. The NEM real time dispatch process is based on similar principles but involves more complex implementation.

Like most competitive electricity markets the proposed design involves trade-offs between precision in economic pricing, complexity and likely cost. The draft report anticipated debate on elements of the trade-offs that have been recommended. This final report provides expanded discussion on key comments made in submissions to provide further explanation of the rationale for the trade-offs.

In developing our recommendations we have assumed functional separation of PWC Generation and clear and demonstrable independence of the System Controller.

We also note the importance of clear and demonstrable independence of the existing PWC Gas group, for example as an independent Gas Trader. Our reason for this is that the independence of generators is compromised if they do not have independent access to fuel. As PWC holds contracts for large volumes of available gas PWC Gas should function as a neutral supplier of gas to all comers.

Finally, the simple design is also readily applied to the Alice Springs and Tennant Creek systems, if appropriate. There is also scope to reduce the flexibility provided for in the design, by for example, presuming new investors will be contracted and thereby making a simpler and lower cost design for these locations.

Implementation

In addition to arrangements related to reform of the structure of PWC and Government's preference for adoption of national arrangements for network regulation, the main areas of work will be required to implement the proposed competitive arrangements are:

- Develop regulatory instruments, in particular the market rules;
- Establish and implement registration requirements;
- Establish the Reliability Assurance Mechanism including:
 - Defining the standard for generation reliability; and
 - Setting the parameters for payment.

We note that equivalent requirements would be expected under other designs. For example, if the alternative approach of an integrated energy-only market design, such as the NEM, were to be adopted, it would be necessary to establish (or confirm) a local generation reliability standard and set up initial risk management contracts and processes which would provide commercial stability and be designed to manage market power of the dominant PWC;

- Establish transparent daily processes for PWC Generation (and in time any new entrants) to make daily submissions for dispatch and for the System Controller to prepare dispatch plans;
- Facilitate training and accreditation in financial instruments within PWC Generation, PWC Retail and the Reliability Manager;
- Establish transparent processes to determine real time energy prices; and
- Establish a settlement processes for real time energy transactions;

We consider informal interim arrangements for day to day operation could be developed readily: these would be based on targeted amendment of the existing regulatory instruments such as the System Control Technical Code (SCTC) and the Retail Supply Code. Clearly these would be bespoke arrangements for the Northern Territory. The interim arrangements we envisage would not be suitable for long term operation or for commercial participation by external parties unless they explicitly accepted the informality. With a focussed effort we consider that informal arrangements could be established in around three months. They could form a prototyping and training platform but would also result in more robust and transparent day to day operations than is possible under current circumstances.

A minimum of 12 months plus consultation time would be required to establish a minimum set of formal arrangements, although these times may be significantly longer depending on the level of effort and external interactions and processes to enlist external assistance. Choices and conditions about timing of handover of regulatory or operational processes to external parties may also influence the time for implementation.

Experience shows that changing arrangements with commercial implications after the fact can be fraught. For this reason, to the extent that interim arrangements do not reflect longer term objectives, for example to use the NER (or other market) as the template for market rules, it should be clear to new entrants what the longer term objectives are from the start.

2. Introduction

Oakley Greenwood has been engaged by The Utilities Commission (Commission) to review and recommend arrangements for a wholesale electricity market suitable for the Northern Territory (the Territory). The full scope of work is provided in Appendix B.

Currently the electricity sector in the three larger systems in the Territory is dominated by Power and Water Corporation (PWC), a state-owned vertically integrated entity. The systems supply the Darwin-Katherine region, Alice Springs and Tennant Creek areas. PWC owns and operates the transmission and distribution networks. It also owns and operates all generation assets in these systems apart from one station under contract to PWC and a number of remote stations. Full retail contestability applies in the Northern Territory although a Pricing Order caps the price for small customers. PWC is the dominant retailer although two smaller entities are registered to retail to customers. The current regulatory regime provides for third party generators to “wheel” energy through the network, but none have successfully done so.

On 13 December 2013, the Territory Government announced that it would separate the electricity retail and generation functions from PWC and create standalone government owned corporations to drive efficiency through more effective structures in a competitive environment. The current opportunities for independent retailing of electricity will be retained and amended if appropriate. New competitive wholesale arrangements are to apply initially in the Darwin-Katherine network with the possibility of later extension to the Alice Springs and Tennant Creek networks. Our task is to recommend a design for the competitive arrangements for wholesale generation.

The three networks are small in comparison to other networks where competitive arrangements have been developed elsewhere in Australia and internationally. Fit for purpose solutions therefore will closely manage overheads and transition costs.

The current arrangements form the starting point for any changes necessary to implement competitive arrangements. They therefore influence the transition path and where appropriate blend compatible existing processes into new arrangements. Further detail on the current arrangements that are relevant to this review are provided in Appendix C

2.1. Structure and conduct of the review

The Territory Government has determined as a matter of policy to introduce competitive arrangements to the electricity sector and has initiated changes in a number of areas including structural reforms noted earlier. Programmes for reform typically include similar objectives relating to reliability of supply, customer costs and reliance on competitive processes. Programmes and associated assumptions are more likely to differ in respect of structure, ownership, fuel diversity and control, technology specific policy and future growth of demand. A clear understanding of the objectives and priorities is therefore essential.

We present our understanding of objectives and the assumptions relevant to our work in the first section. Subsequent sections develop:

- A broad strategic direction for revised arrangements for a possible Northern Territory Electricity Market (NTEM);
- Detailed design elements;
- Governance and organisational matters; and

■ Implementation and transition arrangements.

During the preparation of the review we held discussions with a range of stakeholders, authorities and individuals with previous experience working within the Territory and with experience in electricity market design suggested by the Commission. The purpose of these discussions was to inform ourselves and enhance or clarify our existing understanding about relevant history, policy, technical matters and existing processes and practices and their rationale.

In addition to Commissioners and staff of the Commission, we held discussions with parties and individuals with expertise in electricity market design or the Territory electricity sector including:

Mr John Baskerville/ Ms Anne Tan, Ms Djuna Pollard (PWC), Mr John Greenwood/Mr Paul Ascione (PWC Networks), Mr R Ross/Mr R McCann (PWC System Control), Mr Ian Pratt/Mr Joe Rickman/Mr Peter Levett/ Mr Neil Pitts (PWC Generation), Mr John Tarca (PWC gas unit).

Mr Craig Graham/Ms Samantha Byrne (NT Treasury), Mr David Swift/Mr Ben Skinner, Mr Greg Watkinson (ERA WA- in relation to network planning), Mr Craig Oakeshott, Dr Brian Spalding, Mr Neville Henderson, a representative of Northern Power Group and Mr Alan Tregilgas (Department of Chief Minister).

Mr Allan Dawson (WA IMO) and Ms Ann Whitfield (AEMC) offered assistance of their organisations for subsequent development.

The affiliation of individuals speaking as representatives of their organisations is noted.

3. Objectives

3.1. Government objectives for the sector

The Terms of Reference for this review from the Treasurer to the Utilities Commission notes that the preferred wholesale market arrangements should:

- a) promote the economically efficient, safe and reliable production and supply of electricity and electricity related services of the Territory;
- b) facilitate competition among generators and retailers in the Territory's electricity system, including by enabling efficient entry of new competitors;
- c) minimise the long-term cost of electricity supplied to customers from the Territory's electricity system; and
- d) encourage the use of measures that more efficiently manage the volume of electricity used including the variations between peak and average loads

3.2. Additional considerations

A particular consideration is to enhance the potential for entry by third party generation investors as competitors for PWC. This consideration is not unusual but is not uniform: for example recent reform in Tasmania noted an objective that arrangements ensure the ongoing commercial viability of the incumbent Hydro Tasmania and facilitated retail entry.¹ Understanding differences such as these is important and can influence the features of a design and also mean it is difficult to compare designs for different places unless the objectives for each design are also known.

Attracting third party entry requires that the arrangements be robust and credible including low probability of regulatory risk. In our experience poor or unbalanced design will eventually create a problem leading to regulatory intervention to correct the failing, creating winners and losers amongst incumbents and discrediting the regulatory regime and discouraging new entrants.

To be fit for purpose the design needs to be applicable to the Darwin-Katherine system and also to the smaller systems servicing Alice Springs and Tennant Creek.

A number of policy decisions and proposals have been established as part of the starting point for this review. These are that government is proposing:

- To functionally separate PWC so that generation is separated from networks and electricity retailing as a single standalone government owned corporation; and
- Adoption of national arrangements for network price regulation.

Together with the objective to create an environment that facilitates entry of independent third party generators and retailers, including but not necessarily as integrated gen-tailers, establish boundaries within which this review has been undertaken.

Other requirements which have been taken as implicit in the Treasurer's reference include that reliability of supply must be maintained to an acceptable standard and that costs must be proportionate to the size of the sector in the Territory.

Consistent with the objective of creating an arrangement that is fit for purpose, use of existing governance and possibly software used in the National Electricity Market (NEM) and/or the WA Wholesale Electricity Market (WA WEM) has also been noted as possibly offering a means to control cost, but is not a requirement. Consideration of elements of existing Australian arrangements is consistent with our terms of reference and discussions with the Commission.

1

See - Energy for the Future , May 2012 (policy statement from government)
[http://www.treasury.tas.gov.au/domino/dtf/DTF.nsf/LookupFiles/Electricity-Reform-Report.pdf/\\$file/Electricity-Reform-Report.pdf](http://www.treasury.tas.gov.au/domino/dtf/DTF.nsf/LookupFiles/Electricity-Reform-Report.pdf/$file/Electricity-Reform-Report.pdf) and also update statement by the Minister for Energy and Resources September 2013 at
http://www.electricity.tas.gov.au/wp-content/uploads/2013/09/Ministerial_Statement_on_Electricity_Reform_26-September-2013_FINAL.pdf. Both accessed December 2013.

4. Strategic direction

4.1. Introduction

The first stage of the review establishes a recommended strategic direction for the design we consider is the most appropriate for the Territory within the terms of reference for the review. Analysis to establish a strategic direction considered the general technical characteristics of the industry, the technical and commercial circumstances within the Territory and the policy objectives set by government. Each of these is considered in the following sections.

4.1.1. Industry fundamentals

Well understood technical characteristics of electricity require that aggregate generation very closely matches the aggregate demand of customers at all times. Accordingly sufficient generating capability must be built and be available and real time operation must be coordinated to ensure supply continuously matches demand. Within these requirements electricity sectors can be organised in a number of ways, ranging from fully integrated utilities comprising generation, network and customers through to various forms of contract and market arrangements with competitive generation and retail together with regulated (monopoly) networks.

Regardless of how the sector is managed, there are two very general characteristics of cost-effective electricity sectors especially relevant to competitive market design:

- Investment should occur in the “right” place at the “right” time for the “right” cost, i.e. the life cycle cost should be optimised; and
- Short term operation should make the most efficient use of resources available at any time - least cost dispatch.

4.2. Market design components

The starting point for this review is that Government has determined that the current industry organisation with PWC as a vertically integrated utility will be transformed into a competitive market structure. There will be separate entities formed for generation, retail, networks and other functions such as management of gas, the System Controller and other corporate functions. An objective of the market arrangements for wholesale generation to be recommended by this review is that it be conducive to entry of third party generators and retailers (or gen-tailers) as well as incentives for operational efficiency. Taken together these objectives preclude use of simpler more centrally managed arrangements, for example arrangements that presume participation only by bilaterally contracted combinations of generators and retailers.

Competitive market arrangements need to address the physical, economic, commercial issues and governance of:

- Investment covering new entry (or exit) of generation;
- Energy trading, allowing for forward and real time trading as appropriate:

- Forward trading allows generators and customers to agree on the price for an agreed amount of electricity at a time in the future. Forward trading can occur in a number of ways ranging from simple physical Power Purchase Agreements for generation to market linked financial contracts. Forward trading contracts in a competitive market are arranged directly between generators and wholesale customers. Different market arrangements may assume contracting is voluntary or it can be a condition of participation in the market;
- Real time trading occurs at the time electricity is produced and consumed, i.e. at the time of dispatch. Real Time trading is sometimes described as occurring in a Balancing Market or as an “Out of Balance trade” and is the trading that occurs to reconcile or balance actual generation and actual consumption relative to contracted volumes - net settlement. Alternatively the entire production of all generators and consumption by customers may be accounted as being traded in the real time market - gross settlement.
- Interaction with (regulated) networks. The arrangements for planning and operating the transmission and distribution networks are relevant to this review of wholesale generation markets to the extent that operation of the networks may limit the dispatch from generators in the market. If this occurs, ancillary services or dispatch of reserves will ensure the power system can operate safely. Accordingly these arrangements need to be understood but are not the primary focus of the work;
- Ancillary services are services essential to continuing operation of the wholesale energy trading arrangements; and
- Governance including roles and responsibilities and instruments such as the market rules and associated procedures and mechanisms to amend the rules.

4.3. Single or separate investment and energy trading mechanisms?

4.3.1. Introduction

Two significant differences between competitive electricity markets are:

- Whether the investment and real time energy trading mechanisms are separate or integrated;² and
- The role of contracts between sellers (generators) and buyers (customers).

The choice of single or separate mechanisms has a significant influence on other aspects of a design, especially the role of contracts and how real time market price is formed. The following provides an overview of the generic approaches and is followed by consideration of the situation in the Territory.

4.3.2. The role and impact of contracts

Most electricity markets involve contracts in some form. Contracts may directly underwrite investment in generation assets or indirectly assist investment by de-risking market volatility in the short term market. Contracts may be between separate corporate entities or implicit internal instruments between the generation and retailing activities of a vertically integrated business.

² For example within Australia the NEM uses a single mechanism and the WA WEM uses separate mechanisms.

Contract arrangements may also affect day to day participation in the industry. The inherent variation in customer demand and generator output together with the technical requirement continuously to match demand and supply creates the need for the System Controller to manage real time operation. The variations in supply and demand and the System Controller's actions to maintain balance between demand and supply mean outturn volumes will rarely match amounts established in forward contracts. Accordingly, it is necessary to reconcile actual levels of generation and consumption with contract volumes. The reconciliation can be on a net or gross (market-wide) basis.³

Contracts can be structured around physical delivery or can be financial in nature. Where contracts are for physical delivery, the role of real time market settlement can be thought of as being to identify differences from contract volumes and determine a price (or prices) to settle the implied "unders and overs". Financial instruments can be used for similar effect where a real time price is set from real time operation. Financial instruments create a mechanism that allows buyers and sellers to pay or receive agreed prices for amounts within their contract instruments.

A real time price is typically based on the marginal cost of supply from real time operation. However, the marginal cost of supply is also commonly used for a similar role where contracts are for physical delivery. For example the out of balance price under the existing SCTC uses a marginal buy and marginal sell price depending on the circumstances.

The volume traded in the real time market can be either the total volume of generation and consumption or the residual after accounting for contracted volumes.

4.3.3. Investment mechanisms

Combined, single investment and energy trading mechanism

In a market with a single combined investment and real time energy trading process, often termed an energy-only market (for example the NEM), the real time market price is critical to both investment and energy trading. Where a single process is used individual generators and wholesale customers decide the level of investment on purely commercial considerations. A central body such as AEMO may monitor the process and possibly hold "safety net" powers to intervene if necessary, but is not the primary investment decision maker.

Generators invest on the prospect that real time market prices will allow them to recover the cost of investment and make a profit. Retailers enter contracts to support generator investment against the risk of paying high prices if there is a shortage of generation and eventually scarcity of supply.

3

Also termed a Balancing Market especially where physical contracts are the primary trading instrument

The real time price in these markets must rise to levels that will cover both fixed and variable costs of generation plant. This is because the short term marginal cost of operation alone does not represent the marginal value to customers and in general it does not account for the cost of investing in little used reserve to limit the risk of shortfall in supply. Total long term supply cost is therefore more than the short term marginal cost of supply, although away from peak times it may be close to it. In practical terms, during peak load periods, if investment has been efficient, the price will need to be able to rise enough to cover the full annual costs of the lowest duty cycle generators, as these generators have the highest operating cost and are the last to be called to operate. This price can be very high, in excess of \$10,000/MWh.⁴

Note that the highest price will be related to the number of hours the peaking plant will be expected to run which amongst other matters will be related to the profile of customer demand across a year.

If investors construct more capacity than is needed the real time price falls as reserves are, on average, higher. If there is under investment the price rises.

Separate investment and energy trading mechanisms

In a market with separate investment and operational mechanisms the level of investment is determined by a central planning body. The resultant real time trading may take a number of forms including:

- Wholesale Customers may be obliged to enter contract arrangements with generators for the level of investment decided by the planning body. Each wholesale customer is assigned an obligation related to its forecast demand. This is a very common arrangement in big markets in the north east of the US and is an evolution from earlier large cooperative cost sharing pools which placed capacity obligations on members of the pools,⁵ and
- Requiring that the central body enter into contracts directly with generators to satisfy the required level of reserve or capacity and passing the cost through to the customer base.
 - In the simplest, but most limiting form, known as the Single Buyer Model, such contracts are for full lifetime supply and competition exists only at the time of entering new contracts. Day to day operation is at prices within contracts and by definition there is only one buyer of contracts. Single Buyer contracts are very similar to Power Purchase Agreements used by many utilities. The Single Buyer Model has been used as an initial step to reform in some locations internationally but is widely criticised as lacking transparency, open to political interference and inhibiting independent, innovative, arrangements between generators and customers and also implies long term contingent liabilities on government. The Single Buyer Model is also incompatible with full retail contestability arrangements that have already been introduced into the Territory.

4 The AEMC assessed these matters during consideration of a rule amendment designed to manage perceived market power in the NEM. See <http://www.aemc.gov.au/Media/docs/NERA%20Report-17ccd45b-52cf-4aad-8a1e-88095be3cc9a-0.pdf> and <http://www.aemc.gov.au/Media/docs/NERA-report-55a3f003-7f2b-4f81-b7d4-febdf46fb30d-0.PDF>

5 The Interconnection Operating Agreement between NSW, Victoria and South Australia for trading between the state utilities prior to the NEM was based on similar principles

- Another common form of contracting by a central body is known generically as the Capacity Market. In a capacity market the central body makes a payment to generators (and qualifying demand-side players) to be available for dispatch. The contracted parties also participate in the separate energy trading mechanism which also can be contract based or entirely traded in the real time market.

4.3.4. The Territory situation

Turning to the situation in the Territory, our recommendation is that there should be separate investment and energy trading mechanisms. The following explains our reasoning.

There is on going argument about the advantages and disadvantages of single or integrated mechanisms. Our summary of the argument is that:

Properly implemented in an appropriate industry structure and public policy setting in a mature industry situation, a single integrated approach provides the purest economic and market oriented solution. If these conditions are not present separate mechanisms are more appropriate.

A significant reason for recommending separate mechanisms for investment and energy trading is that an integrated, energy only, mechanism would be close to unworkable as a competitive instrument in the presence of a single dominant generator. Single integrated mechanisms require appropriately high prices. We envisage highly interventionist regulatory measures would be needed to control the real or perceived market power that might lead to inappropriate prices: creating an essentially regulated outcome. Further very high real time prices are often politically uncomfortable and there are often calls for such prices to be capped, even when economically justified. We have not undertaken quantitative analysis for the purposes of this report, however, the number of generating units and potentially separate power stations in the Darwin-Katherine system is likely to be a borderline number for unfettered energy-only competition and the situation in the smaller Alice Springs and Tennant Creek networks well below competitive numbers.

More fundamentally, investment within a market with an integrated mechanism relies on potential investors responding to forecasts of future price based on forecasts of future demand. Our expectation is that electricity demand in the Territory will reflect its developing economy and has the potential to grow rapidly in potentially large steps. We note that changing resource development activity has impacted forecasts in the larger WA WEM and impacted assessment of capacity needs there. Potentially the Territory may see similar sized but proportionally larger jumps due to policy initiatives, resource developments and if the network is extended to currently isolated townships. As a result forecasting the potential for future high prices that provide investment incentives in an energy only environment will be problematic.

For these reasons separate investment and energy trading mechanisms are recommended. A separate investment mechanism implies some form of capacity market. Section 5.2 presents more detailed consideration of the design of the RAM for this role.

4.4. Energy trading

4.4.1. Introduction

The concepts of forward and real time trading were introduced in section 4.2. Forward trading can be of critical importance to participation in a competitive market and the form of compatible contracts can be influenced by the design of the rules for the real time market.

The formal design of a market generally does not define the commercial components of forward trading instruments. Accordingly the focus of competitive market design is generally on the real time market - sometimes to the point where understanding of the crucial role of contract instruments is lost.

The remainder of this section deals with the strategic direction of energy trading to be addressed in market rules, the real time market. Reference to forward trading contracts is made as needed. The real time market is inextricably linked with the dispatch process overseen by the System Controller.⁶

4.4.2. Real time trading and the dispatch process

Section 4.3.2 described the need for short term or real time physical coordination of a power system and introduced options for real time operation to be based around contracts or system wide dispatch. This section expands on those options and concludes by recommending that real time operation should be based on a security constrained gross dispatch and settlement concept. The following describes the matters considered to reach this view.

Firstly we review three broad options for real time dispatch in a competitive market environment.

The first option is to set up the dispatch and associated settlement as a means for contracted parties to “wheel” power from generators to customers and to require the individual contracted parties to adjust their particular supply to their particular demand. This option is not recommended as it is an onerous obligation on the third parties and becomes increasingly complex the more participants there are and will inevitably still end up with real time dispatch disparities that will need to be bought and sold through the System Controller. It also ignores the potential for a simple least cost dispatch with loss of economic efficiency.

We note that provisions of the current SCTC are based on this concept but have not been utilised by third party generators for some years. Our brief from the Commission notes that these provisions are considered as “by far the most significant barrier to private sector investment.....”

A second option also facilitates dispatch according to contracted positions but provides a common real time balancing service managed by the System Controller without a formal requirement to adjust individual generation to match individual demand. An after the fact settlement process deems the use of the real time service depending on whether each party’s generation and consumption matched contract amounts. Market Rules determine the price for the real time service. This is an option favoured by parties with a view that the participants should be subject to as little control or management from a central body (the System Controller) as possible.

A third option is to separate dispatch from contracts and call on the System Controller to dispatch available generation to meet aggregate consumption on the basis of the cost of operating each available generator. An after the fact settlement process treats all production and consumption as being transacted in the resultant real time market or alternatively only amounts net of contracts as advised to the settlement process. Market Rules determine the price for the real time service.

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The term System Controller is the term used in the Northern Territory for the equivalent role of System Manager (WA) and System Operator in many other locations.

In its most centralised form this option sees the System Controller deciding both dispatch and commitment of generating units. Unit commitment can be important where a power system includes large boiler-fired steam turbines that can take many hours to start and is discussed further in Section 5.4.

In principle, each of the options is capable of delivering the same, economically efficient result. However, the first two options will only optimise use of available generation if the contracts at the time of dispatch are for the optimum mix of generation. To assist market participants optimise their contract portfolios accounting for up to date knowledge of plant conditions and demand, many markets operate a central contract exchange the day ahead of dispatch - a day-ahead market. Day-ahead markets provide a means for generators and customers to make last minute adjustments to contract volumes and to lock-in prices. They also provide commercial protection for unit commitment decisions, and where required, to make nominations for fuel or set up hydro storages for the following day. The third option is designed to ensure a system wide optimum dispatch but relies on the System Controller receiving adequate information about the status of generation plant and making accurate predictions about demand and performance of generators.

In each case where actual generation or consumption differs from contracted volumes the parties are effectively buying and selling the difference as a real time trade. Real time trades can also result from actions by the System Controller as part of a system wide dispatch optimisation and where a generator or customer deliberately relies on buying or selling in real time - at spot. Accordingly some energy will always be transacted in real time and a price has to be established for the trade(s). The homogenous nature of electricity and networked nature of the industry means that these trades can only be reconciled on a market-wide basis. A variety of methods are used to determine a price for real time trades ranging from:

- A matching of contract prices, for example the highest priced buyer is deemed to have bought from the lowest priced seller. This approach is intuitively attractive from a contract perspective and was used previously in a number of older US pools; to
- A single market price for all transactions calculated according to market rules. Typically the price of the highest priced generator in service is used to set the price as this represents the marginal cost of supply at the time and is used very widely.

The options described above were presented in the context of intuitive physical contracts. A variation on the third option is for contracts to be financial rather than physical - hedges - providing there is a suitable reference price available for settlement. Later discussion will conclude that a market designed with the expectation that financial contracting is likely to be widely used has many attractions and is preferred.

4.4.3. The Territory context

The previous section discussed the generic options for real time dispatch operation. In considering which broad approach is appropriate for the Territory, we note that a number of characteristics of other power systems that influence that choice elsewhere do not exist or are much less significant in the Territory. As a result the options for a market design in the Territory are less constrained than elsewhere. In particular:

- Aggregate customer demand from one day to the next in the Territory is relatively predictable and does not exhibit the large swings seen in states and cities with highly variable weather conditions. While demand in the Territory power system changes across seasons and from week-day to week-end it can be predicted with much more certainty than in other places;

- The scheduled generation fleet in the Territory is predominantly gas fired and is likely to be so for the foreseeable future. Solar or other renewable resources are expected to grow but none of these is likely to be scheduled on a discretionary basis and will either present to a wholesale market at their prevailing capacity or be an offset to demand. However, depending on the technology involved, market demand may then become more variable over time requiring techniques to forecast the variations to retain certainty;
- Gas fired technology has relatively short start up times and hence generator unit commitment decisions in the Territory can (and are currently) made much closer to the time of dispatch; and
- Contractual and administrative arrangements for when changes to gas quantities are required are flexible and can be made during a day quite readily in the Territory.⁷ This situation is in contrast to other locations with restrictions and or cost penalties for change. In any event because the customer demand is more predictable and gas is the dominant fuel, the magnitude of any changes to a daily nomination is generally small.

As noted earlier, market arrangements elsewhere often include day-ahead contract trading to allow participants to manage the physical and commercial risks of change. Our analysis suggests day ahead arrangements do not appear to be needed in the Territory (although individual parties would be free to establish a day ahead forward contract if desired).

In the first two generic options for dispatch described in the previous section, a system wide least cost dispatch outcome will occur only if all of the contract arrangements function with perfect foresight and knowledge. Arguably in a liquid contract environment this will be the case. The third option can deliver optimised dispatch in principle. The need for the System Controller to make decisions about unit commitment is removed in some markets by requiring generator participants to make these decisions and advise the System Controller. However, these decisions will only be efficient if the generators have accurate information about the day-ahead outlook. Forecasts of price are often used to inform participant decisions about commitment.

However, in the Territory at present, the only unit commitment decision required more than an hour ahead relates to the Combined Cycle (CCGT) block at Channel Island and the Pine Creek generators and together these rarely cover the minimum demand. Accordingly, CCGT plant would be expected to run whenever available, subject to system security operating constraints. Forecasts would become more important if additional CCGT plant were to enter the market in the future.

Accordingly a least cost optimised dispatch would appear to be readily achievable with a simple submission of dispatch price to the System Controller. Dispatch price therefore should be related to or capped at the demonstrable cost of production in recognition of the dominance of PWC and also as a means of simplifying the commercial trading arrangements within participants on both sides of the market. Individual parties would however be free to establish financial contracts between themselves if appropriate.

A single market clearing price can then be established from the resultant dispatch and used to settle the market.

This arrangement is similar to system wide dispatch process or the balancing market design elsewhere including the NEM, New Zealand, Singapore, Philippines, Alberta (Canada), South Korea and Texas (US).

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From interview with PWC gas contract managers

The arrangement is also similar to the outcome of the real time balancing market that is preceded by bilateral contracting and a day-ahead energy market auction (the Short Term Energy Market (STEM) in the WA WEM. The day ahead processes are important in the context of the WA WEM given the volatility of demand, mixture of generation technologies and constraints on changing gas quantities at short notice that are not present in the Territory.

Note, the often discussed high price outcomes in the NEM are part of the single combined investment and real time energy trading design concept and for this reason can reach very high levels.

4.5. Market rules template

Rules for the operation of a competitive electricity market are significant pieces of drafting and can be time consuming and costly to prepare. In part this is due to the requirement for close coordination of physical operations and the impact this has on commercial transactions discussed in previous sections. In practice the formal Rules typically do not cover all details and subservient procedures are used to document matters that are essential to the implementation of the principles underpinning the rules. The decision about whether a matter should be covered in a procedure or the rules is a matter of judgement by governance bodies.

Also as discussed, within a given strategic design direction there is a number of choices about the design of individual elements. A number of sets of market rules have been developed and are in use in different markets including the National Electricity Rules (NER) for the NEM and the Market Rules for the WA WEM. Our terms of reference ask us to consider the applicability of the NER and the rules of other markets including the WA WEM rules.

Subject to relevant agreement and authorisation from the relevant body appropriate use of an existing set of rules, especially rules from an Australian market, will reduce the cost and time for implementation. Use of existing Australian rules will also reduce regulatory duplication and therefore cost for market participants operating in those other markets to participate in the Territory.

The strategic direction presented in this chapter has similarities with the security constrained gross dispatch of the NEM and the separate capacity mechanism of the WA WEM. As a result neither set of rules is immediately applicable without change. Similarities and differences between them include:

- The Reserve Capacity Mechanism of the WA WEM provides detailed rules for determining and accrediting and if necessary acquiring capacity in a separate process to energy trading. The NEM includes only a broad procedure for monitoring the level of capacity and if necessary acquiring additional reserves;
- Both the WA WEM and NEM develop a single clearing price from real time operation (by region in the case of the NEM and not a nodal price at each connection point as occurs in New Zealand and some other markets internationally);
- The WA WEM and NEM each use gross dispatch principles. The NEM is a direct price based gross dispatch. The WA WEM balancing market dispatch uses a balancing merit order calculated by the market operator and passed to the System Manager (WA equivalent of the NT System Controller) formed after day ahead contract trading processes are complete;
- The WA WEM requires generators to make submissions that ensure security constraints are observed while the NEM provides for the system operator (AEMO) to apply security constraints as part of the dispatch process;

- The WA WEM separates the Market Operator function (including receiving submissions for dispatch and preparing pre dispatch) and System Operator functions and the rules deal extensively with the interactions between them. In the NEM AEMO performs both functions;
- The NEM makes no distinction between individual generators. In the WA WEM Verve Energy, the state owned generator, is treated differently to other generators (Independent Power Producers) in the nature of dispatch submissions and in the dispatch process. Verve is also the default provider of balancing and ancillary services although there is also provision for Verve to offer individual generation facilities on the same basis as units of Independent Power Producers;
- Both markets have features which are not proposed for the Territory, for example the STEM in the WA WEM and provisions for inter-regional trading and market ancillary services in the NEM. Deletion or otherwise bypassing unnecessary rules should be relatively simple however.

In principle either set of rules could be modified to suit the strategic direction proposed. However, there are more operational, commercial and governance features of the rules for the WA WEM that will need to change than in the NEM. Many of the changes to the NEM will be to remove or bypass provisions. The aspect of the WA WEM rules that is most applicable to the proposed strategic direction is the Reserve Capacity Mechanism and this is relatively self contained in the WA WEM rules and therefore readily replicated as required. Finally, decisions have already been taken by government to seek transfer of network regulatory functions for the Territory to the NEM.

Accordingly we propose to discuss implementation of detailed design elements on the assumption that the NEM will be the template for the Territory.

However, as discussed briefly in section 11.1, the existing System Control Technical Code includes provisions for wheeling of energy by independent parties that while considered problematic in its current form would appear to be able to be amended relatively simply and form the foundation of rules.

4.6. Summary of recommended strategic direction

The key features of a wholesale electricity generation market we recommend for the NEM are:

- Separate reliability assurance and energy trading mechanisms;
- Reliability assurance mechanism to involve
 - A central reliability assurance contracting body, possibly within an expanded System Control function, setting minimum requirements for generating and controllable demand side investment;
 - A regular tendering process for owners of generating and demand side capacity to submit offers to contract with the reliability body or submit notice that contracts have been entered into with customers for an equivalent amount of capacity;
 - Term of contracts to reflect a balance between investment certainty and prevailing supply/demand balance; and
 - Reliability assurance contracts to be financial in nature and impose a financial penalty on holders of a contract which are unavailable for operation when reserve is low.
- Energy trading mechanism
 - A security constrained gross dispatch pool managed by the System Controller;

- Dispatch to be based on availability submissions from generators with prices initially required to be no more than demonstrable short run cost (with guidelines as to how to assess cost);
 - A marginal clearing price from real time operation; and
 - Settlement of the pool to allow for gross or net volumes at the discretion of market participants; and
- Market rules to be developed using the NER as a template.

5. Design elements

5.1. Introduction

The previous chapter concluded with a recommended strategic direction for the design for a NTEM. This chapter develops detail and provides guidance on areas for further specific work that will be required to implement the direction.

5.2. Reliability assurance mechanism (RAM)

Our recommended strategic direction includes a mechanism specifically designed to ensure an efficient level of capacity. We have termed it a Reliability Assurance Mechanism (RAM) to distinguish it from a standard physical capacity market.

Arrangements based on contracts for physical capacity have existed for many years in international markets and power systems and provide models that can be followed. Each has advantages but also disadvantages, especially the requirements to accredit and test physical capability, monitor day to day availability, penalise failure and allocate costs to the customer side of the market. Submissions to the draft report also noted some of these issues which are an unavoidable consequence of separate mechanisms.

More recently markets have begun to use financial instruments linked to the operation of real time energy markets. These arrangements are less complex than physical capacity markets as they place greater, but not complete, reliance on financial incentives for the presentation of capacity. Although they are voluntary, cap style financial hedge products in an energy only real time market such as the NEM (and New Zealand and elsewhere) fulfil a similar role. The WA WEM Reserve Capacity Mechanism is based on physical capacity.

Our aim is to recommend a financial instrument for the NTEM Reliability Assurance Mechanism to take advantage of the lower complexity and therefore lower overhead in administering a financial mechanism compared to a physical mechanism. Submissions to the draft report were supportive of a separate mechanism related to investment but, as expected, found the discussion on the particular design to be the most contentious aspect of the recommendations. For this reason this final report expands the consideration of this part of the recommendation.

Earlier discussion of the strategic direction (see section 4.3.3) noted two broad types of separate investment or capacity mechanism:

- Centrally administered regimes which involve a central market body contracting with or making payments to generating and demand side capacity providers and recovering the costs from the load side of the market. It is also common for market rules to exempt parties from this arrangement where they have voluntarily contracted bilaterally; and

- Regulatory or market rule obligations for market participants to demonstrate a level of contracting has been arranged for a minimum level of capacity. Under this type of arrangement a market body must monitor whether the required level of contracting has occurred and generally market rules will impose penalties or a de facto contract if insufficient capacity is contracted.

Both approaches have merit but the draft report recommended a central approach in preference to mandated contracts. In both approaches a central body must set the minimum level of capacity required and as a result any over-estimate of the requirement will be paid for by the load side, but by different means. This is unavoidable when a central agency is assigned accountability for managing the level of capacity. However, it also allows the investment risk to be shared between the generation and load sides of the industry and is thus more conducive to new investment than a situation where the risk is carried primarily on the generation side, as it is in the NEM for merchant generation. However, there are differences between central and mandatory contract arrangements in respect of:

- Retail contestability: Under a mandatory contract arrangement a secondary market for contracts will be required to accommodate changes in a retailer's demand when consumers switch retailer as the affected retailers will need to adjust the amount of mandatory contract they hold. The market operator's IT systems would need to record customer switching and contract levels. While a voluntary secondary market may also evolve under a central approach to facilitate energy trading, it would not be as essential;
- Presumption of contracting: Arrangements with mandatory contracts between generation and retail presume market participants are always under contract and are thus not compatible with participation of uncontracted merchant generation or wholesale customers. In the normal course of events it is likely that it will be prudent for both generation and wholesale customers to enter contracts. However, as discussed in the draft report, the design has aimed to avoid making contracting a condition of participation. One submission noted that mandatory contracts could take the form of typical financial hedge contracts and in the future the requirement could be removed and the parties decide if they wish to continue them. This is clearly an advantage of mandatory contracting, but on the other hand removing the requirement for contracting would be a single one-off event at some point in the future. The recommendation for the RAM is to use financial contracts which, although different in form, can also be retired relatively simply. The mandatory contracting approach would, however, use a form closer to a form likely to be used on a voluntary basis, but our view is that this advantage is outweighed by the ability to accommodate merchant generation and reducing overheads on participants described immediately below;
- A centralised capacity mechanism involves less overhead on the part of participants but more direct involvement of the market operator as it is a counterparty for payments to capacity (in addition to its role to assign a capacity rating to each generating facility which it would need to do under all options). The onus for ensuring sufficient contracting will be on the market operator and relate to system wide capacity rather than individual participants who may be penalised if they do not achieve the correct level of cover. A central approach is therefore likely to result in lower participant costs (and risks) but higher market operator costs which would be recovered in fees. Finally it is also worth noting that neither the NEM or the WA WEM uses the mandatory contracting approach and it would therefore be a new regulatory feature within Australia; and
- Mandatory contracts imply standard contract form which may (but not necessarily) limit innovation in contract terms and conditions and raise the question of how external trading platforms and instruments such as on the ASX would be accommodated.

On balance a central contracting approach using the Reliability Options concept is recommended for the RAM. The proposal blends the advantages of the assurance of contracts with capacity to give greater assurance that sufficient capacity will be available in a similar way to the WA WEM Reserve Capacity Mechanism, with the advantages of financial instruments used in the NEM for implementation. Although the individual elements of the mechanism are well proven, full details will need to be developed as part of the implementation of market processes and rules in a form suitable for the Territory. We note that the detail of any form of capacity or reliability mechanism would also need to be established for application in the Territory, for example to determine the level of capacity to be accredited and the impact of local fuel contingency arrangements.⁸

For the purposes of discussion we have termed the central agency the Reliability Manager. In practice the Reliability Manager can readily sit within the corporate planning function of the current PWC after it is functionally separated from other commercial groups or in another government entity.

The Reliability Manager would determine the capacity requirements for specified future years for the overall power system - this would be in accordance with a defined reliability standard and identical to the planning currently undertaken by PWC. It is the same activity that would be required for a physical capacity market - also see Section 5.2.1. This role is also similar to the monitoring function undertaken by AEMO in the NEM and the capacity requirement undertaken by the Independent Market Operator for the WA WEM Reserve Capacity Mechanism.

The Reliability Manager would call for tenders for generation/demand side capacity to enter financial contracts with the Reliability Manager. Under the contracts the contracting parties would reimburse the market settlement system for the difference between the prevailing real time market price and an agreed strike price. The contract would therefore operate in the same way as a cap hedge contract in an energy only market such as the NEM, except the counterparty would be the Reliability Manager.

In calling for tenders the Reliability Manager will have announced a contract strike price set at a margin above the highest expected real time price in the market - recalling that submissions to the real time dispatch process are to be cost based but will also include an administered low "reserve adder" similar to the concept used in some north American markets. Successful tenderers will receive a contract fee to be funded by a charge on wholesale customers. The concept of the "reserve adder" received attention in a number of submissions to the draft report. The "reserve adder" is an administrative amount that is added to the marginal price to reflect the increasing stress at low reserves. The value of the adder is a trade-off between attempting to price an increasing risk of involuntary interruption to customers and risk of adverse financial impact on exposed customers and generators.

Values up to a number of hundreds of dollars would be typical, but possibly less given the significant step in price that will occur when generation operating on diesel is needed in the Territory. Because it adds to the market price a "reserve adder" increases the incentive for reliability at times of low reserve and the opportunity for demand side response when it is most valuable. However, it is not designed to reflect the full scarcity value of load for the affected half hours as the NEM price does.

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Examples of international discussion of Reliability Options can be found at <http://stoft.com/metaPage/lib/Bidwell-2005-06-call-option-ICAP.pdf> and <http://www.cramton.umd.edu/papers2010-2014/cramton-ockenfels-stoft-capacity-market-fundamentals.pdf>

One way to view any capacity mechanism, including the RAM, is that because customers pay for it across the year they are effectively hedging against the alternative high prices that would otherwise be needed in the same way that customers in an energy only market such as the NEM could hedge by purchasing cap style hedges. Viewed from this perspective a capacity payment has some attributes of mandatory contracts.

As the RAM contract is to operate as a financial hedge against the real time market price, failure to be available for dispatch when price is high will expose the holder of a contract to paying the difference between the announced strike price and the prevailing real time price (the marginal cost of supply plus the reserve adder) back to the market. The risk will be related to prevailing conditions and investors will therefore need to understand the potential exposure under this arrangement. In this regard the broader recommendation for the NTEM includes a requirement that prices be cost based and discussion in section 5.6.5 notes that the detailed rules around setting of real time price should consider the impact of extreme events, especially due to weather, to ensure the rules for market pricing do not create inappropriate risks. Further, as part of the detailed design it may be appropriate for an additional charge to be included for failure to present capacity.

As part of detailed work to implement this proposal, provisions will need to be included to ensure generators are not inappropriately exposed to double payment if they also wish to hedge the energy price with retailers. This is a problem discussed by the Office of Electricity and Gas Markets in the UK in consultation on the potential to introduce a capacity market into the electricity market in the United Kingdom.⁹ Similar attention will need to be given to the exposure if not all contracted capacity is needed to meet demand. This protection is likely to be available through a combination of net settlement and load following provisions. The duration of contracts and consideration of staggered dates for contracts to mature will also be considered in developing the implementation arrangements

Finally, we note that the Utilities Commission has concluded new capacity is not essential for a number of years, although this does not preclude competitive new entrants. There is an opportunity to develop and refine the mechanism if necessary before this time. However, it is important to note that the mechanism proposed for determining the real time energy price is not, by design, expected to fully remunerate generation and therefore a payment equivalent to the contract fee described above will be necessary and will need to be determined during the market transition process. A similar payment would be required under any form of capacity mechanism.

Another variation in design of a centrally administered capacity payment was also raised in a submission and involves awarding capacity payment according to incremental system value. This approach has merit in principle. However, it would be a larger departure from practice in other markets in Australia and would therefore be a bespoke approach. Alignment with practices and expertise elsewhere in Australia was one of the factors to be taken into account in the review. The RAM as proposed is recommended as it strikes a balance between functionality in the context of the Territory and alignment with elsewhere.

5.2.1. Generation reliability standards

The RAM will require the Reliability Manager to tender for an amount of capacity that provides a minimum reliability of supply. But what level?

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Electricity Market Reform - Capacity Market, Impact Assessment. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf

Traditionally reliability of power systems has been expressed in terms of the level of customer demand that is not met or is involuntarily interrupted due to a shortage of generating capability.

Typically the level of load not supplied has been measured in terms of the frequency (Loss of Load Probability or LoLP and Loss of Load Expectation LoLE), duration (Loss of Load Hours or LoLH) or the amount of interruption (Unserviced Energy or USE and Energy Unserved or EUE).

Alternatively a reserve margin is called for that aims to manage the conditions under which there will not be interruption: for example a minimum percentage margin or an “n-X” criteria (where X is the number of generators that would need to be unavailable for operation at the time of peak demand before there is insufficient generation to meet demand).

The measures are interrelated as the same capacity requirement in two markets generally will result in different delivered reliability the two systems. For example the NEM standard for USE of no more than 0.002 per cent of annual demand to be at risk results in LoLH of around 3 hours per year. The WA WEM standard which is based on the most stringent of a percentage margin, n-1 and USE no greater than 0.002 per cent, delivers USE very much better than the 0.002 per cent. This is due to the very peaky temperature sensitive demand in WA meaning the reserve margin leg of the standard is dominant. In the Territory, n-1 is likely to deliver higher USE than the same standard in the WA WEM because the demand is less temperature sensitive and therefore is closer to maximum more often. Accordingly the n-X form of standard may be less appropriate.

One submission to the draft report anticipated difficulty in determining a reliability standard or reserve margin due to the potential effects of major storms and cyclones. In part this concern highlights the importance of considering local conditions and the role of policy decisions in setting reliability standards noted in the draft report. It is important to be clear about what the reliability standard and resultant level of investment is attempting to achieve. In this regard it is likely to be impractical to avoid some interruption of supply during cyclones and major storms as these events are likely to impact transmission and distribution networks and interruption risk is affected more by network capability and performance than by the level of generation investment at these times.

The detailed arrangements in the WA WEM and NEM each recognise local conditions either in the way the standards are set or reported. The WA WEM does not attempt to set a reserve margin in the electricity system to cater for major interruption of gas supply but does establish a requirement for dual fuel on some generating plant and the WA WEM reliability standard is based on the more stringent of two measures of reliability. NEM reporting on reliability performance distinguishes between security of operation and reliability (generation adequacy). The NT reliability standard should also account for local conditions and policy choices. For example it may be appropriate for the Territory standard to consider normal and abnormal conditions such as in the event of cyclone and be prepared to carry additional reserve or require reserve to be located in diverse locations.

Finally we note that economic value has been used to assess network reliability requirements for a number of years. Market authorities are increasingly considering the economic basis for generation reliability standards with a view to creating standards that match customers' valuation of reliability to the costs incurred in acquiring or constructing the generation and demand side capacity. Current initiatives for generation investment to be based on customer value are focussed on determining what that value is. This is problematic as it has to represent the entire customer base - see for example advice to the Standing Council on Energy Resources by the AEMC, recommending that economic value be used to benchmark reliability settings but not directly determine them.¹⁰ Industry literature is illustrative of the state of debate including that there is criticism of the longstanding "1 year in 10" standard used in North America as being uneconomically conservative.¹¹ However, no Australian systems employ this form of standard or the equivalent level.

The key matters for operation of the proposed NTEM Reliability Manager will therefore be:

- What is the form of generation reliability standard to be employed? and
- What is the level of the chosen form?

The answers to these questions involve significant policy choice regarding which aspects of generation reliability are most valued in the Territory.

5.3. Real time energy market

5.3.1. Introduction

Our recommended strategic framework for the NTEM developed in the previous chapter provides flexibility for participation of both independently contracted generator-customer combinations and independent merchant generation and customers.

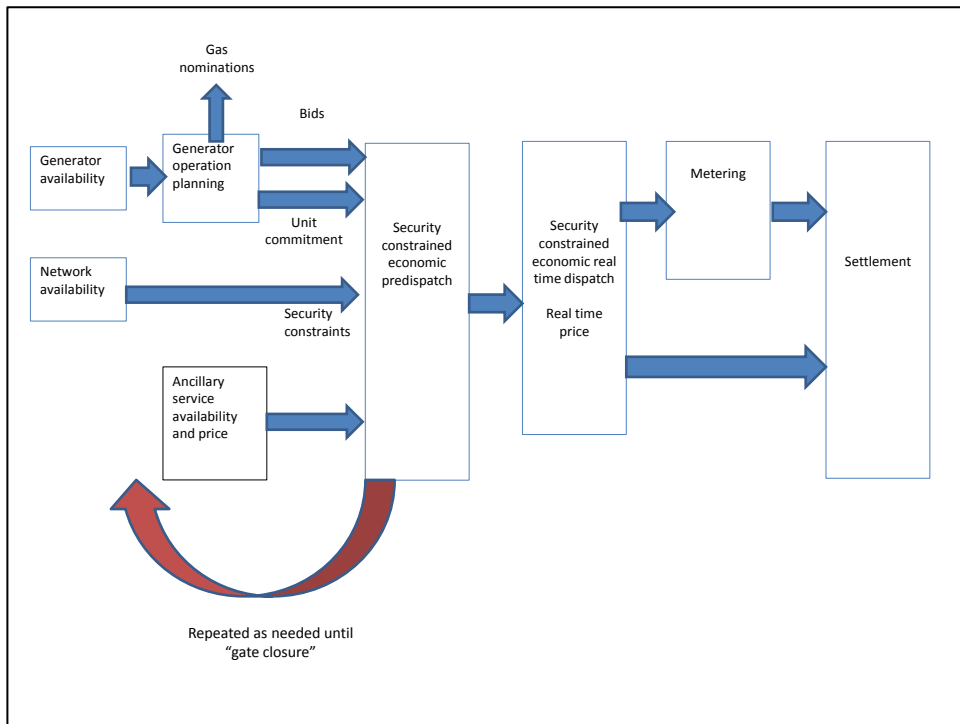
Physical operation of the power system is to occur through a simple security constrained gross dispatch process. A single real time market price would be set from the dispatch.

The key steps are illustrated in Figure 1 where it can be seen that the process steps are similar to those used by PWC at present and described in Appendix C. However, the conduct of each step will need to be more robust and transparent than occurs, or is needed, at present.

¹⁰ AEMC 2013, Advice to SCER on linking the reliability standard and reliability settings with VCR, Final Report, 20 December 2013, Sydney. Available at <http://www.aemc.gov.au/Market-Reviews/Completed/advice-on-linking-the-reliability-standard-and-reliability-settings-with-vcr.html>. Accessed February 2014

¹¹ See for example: A submission to the US Federal Energy Regulatory Commission in relation to an application for approval of a tariff based on the "1 in 10 year" standard <http://wilsonenec.com/Wilson-comments-RM10-10-Dec-27-2010.pdf>. The Commission's decision noted it was not required to determine if the standard was appropriate only that it meet certain tests that broadly required it to be reasonable. See <http://www.ferc.gov/whats-new/comm-meet/2011/031711/E-7.pdf>

Figure 1 Energy market process



In the settlement stage participants would have the choice of settling their entire real time generation output or consumption through the central settlement system or only the residual of their contracted amounts. It would be the responsibility of participants to arrange settlement of any energy not settled through the market settlement system on a bilateral basis.

Within the gross dispatch process generators will be required to state the price and volume they have available for dispatch and the System Controller will accept the lowest cost combination of offers needed to meet demand.

Importantly, contracts between participants will not be a factor in the decisions of the System Controller. Generators concerned about operating limits or related process requirements that require a minimum generation level will be able to communicate this through their submissions: in the first instance by submitting a low price for all or part of their capability and also by a defined minimum which can only be overridden in an emergency in the power system. Participants concerned that this arrangement potentially transfers control of their plant to the System Controller should note that all power systems provide overriding authority to System Controllers to ensure the secure operation of the power system regardless of whether access and dispatch is based on physical contract or gross dispatch as proposed. In a formal market based arrangement the independent System Controller is obligated to utilise generation in the priority defined by the submissions of the participants.

In general generators will have at least some commercial flexibility in their output level and will benefit from participation in the gross dispatch process and associated settlement. The dispatch process will call on the lowest cost combination of generators at any time. The real time market settlement process will allow them to meet their contract(s) making use of cheaper production from the market where it is available, rather than from their own resources.

Security constrained dispatch is essential for secure operation of a power system and would be developed by the System Controller for real time operation and account for requirements for matters such as spinning reserve and network loading limits.

One of the detailed choices available in designing market-based arrangements is whether the real time market prices should be based on the physical dispatch or on a theoretical dispatch based purely on energy prices from generators with compensating payments added or subtracted if the security constrained physical dispatch varies from this. A simple security constrained dispatch as the basis for prices is simpler but also creates some commercial risks that need to be accounted for within the detail of settlement. Our view is that these risks are manageable and the simpler system with real time price set from security constrained dispatch should be adopted.

5.4. Generator unit commitment

Unit commitment of a generating unit is the process of starting a unit that is off line and connecting, or synchronising, it to the power system. For technologies such as coal fired steam boilers this process can involve considerable cost and take many hours. In power systems where these technologies are present, unit commitment is a significant operational decision that can also impact the level of reserves while a unit is starting and the cost of operation.

Unit commitment decisions can be made either by the generator (self commitment) or by the System Controller (central commitment).

The generation fleet in the Territory is dominated by gas turbines that can start quickly and therefore unit commitment is straightforward and does not require inclusion of market design features including day-ahead contract rounds.

A common principle for market design is for the parties that take decisions to be held commercially accountable for them. Applying this principle, if the System Controller were to take unit commitment decisions, and if in hindsight a unit commitment was later shown to be commercially unnecessary, then the additional cost should sit with the System Controller, which in effect would mean that customers would carry the cost through the fees charged for the System Control function. This is one reason why many markets including the NEM and WA WEM use the self-commitment approach. It is also the approach used between the generation division and System Controller functions in PWC at present.

Given self-commitment is the current approach in PWC and is common in other markets self-commitment is proposed in the NTEM.

5.5. Dispatch bids and offers

5.5.1. Form and constraints on submitted prices

Competitive markets recognise that generation plant may have different efficiency and cost at different output levels (for example if water injection is used) and may also have minimum output levels below which a particular generating unit cannot operate and must be shut down. Generators may also wish to ensure they are being dispatched and earning revenue to cover financial exposure under contracts if market prices are above a threshold in their contracts. For this reason generator bids can generally be made in a number of "price bands" using positive and where appropriate negative prices. Ten bands are commonly allowed and appear to be a practical and adequate number of bands.

The proposed wholesale market design for the Territory will require a similar facility for generators to convey prices in a number of price bands and the practice of providing 10 bands is proposed to continue. However, fewer bands are expected to be practicable if the full quota of 10 bands is difficult to achieve initially.

5.5.2. Prices to be cost reflective

PWC will hold an overwhelmingly dominant and possibly monopoly position in the first years of a market and will therefore have significant market power.

A major objective of introducing a competitive market arrangement is to establish the conditions conducive to entry of new generation and also to expose PWC to ongoing competitive discipline in its day to day operation. A potential new entrant is highly likely to regard the dominant position of PWC as a major commercial risk regardless of whether PWC has, or will in the future, take advantage of its dominant position.

Management of market power is unavoidably a regulatory intervention. Two options for managing market power in electricity markets where industry structure means one player is dominant are to limit generators to submitting prices that are related to their short run operating costs and to impose contract obligations on the participants that negate the benefit of the exercise of market power.

Generally contracts are preferred as the means to manage market power in this situation. They are a less complex mechanism and can be in the same form as typical market based contracts. Contracts also have less risk of creating unintended distortions that can arise from restrictions on bid prices.¹²

It is also important to note that operating cost based restrictions on bids is only rational where there is a capacity payment in the market design. In markets such as the NEM and in New Zealand, Singapore, Texas and Alberta for example, prices must rise above short run generator cost in order to provide revenue to cover fixed costs of generators. As a capacity payment is proposed for the Territory, limiting bids to short run cost is an option.

Vesting contracts initially applied in all NEM jurisdictions for the volumes retailers were required to supply under franchise. In the WA WEM a vesting contract was established between the state owned generator and state owned retailer to cover franchise customer, other generator-retailer parties were commercially linked or were part of vertically integrated businesses. The WA WEM also requires that generator bid prices be cost reflective.

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Examples of unintended distortions due to restrictions on bid prices include a) in the ERCOT market in Texas in the US where any participant with significant market share is at risk of regulatory sanction if they do not bid at cost, but the market has been shown to suffer from inadequate revenue to reward new investment and b) in the WA market there was initial reluctance to bid negative prices when faced with the risk of overnight reductions below minimum operating level of generating units due to high levels of output from wind generators - this has since been rectified by changes to price guidelines and significant change to the market design,

The situation in Tasmania provides a useful comparison. Tasmania participates in the NEM via its interconnection to Victoria over Basslink. The Tasmanian government has recently established a requirement that the dominant state owned generator, Hydro Tasmania, stand in the market offering a number of forms of contract at regulated prices. The Tasmanian government's objective in doing this is to facilitate retail competition. It was concerned that new entrant retailers may not have access to competitively priced contracts. In particular, for situations where the retailers were contracting with new entrant generators (or generators located elsewhere in the NEM), but dependent on Hydro Tasmania at times when Basslink is fully loaded (or other generators unavailable). The prices of the standing contracts are to be related to the Victorian market price on the basis this reflects prevailing competitive position in the NEM and the effective value of Hydro Tasmania's water in storage.¹³

A broadly similar approach could be taken in the Territory and PWC assigned vesting contracts or required to stand in the market to offer regulated forms of contract. However, as there is no benchmark equivalent to the Victorian price representing competitive NEM prices it would be necessary to determine a reference price for any standing contract. With the current structure this would in effect explicitly regulate PWC generation's return limiting its exposure to competition. Further, as the Territory has adopted full retail contestability regulated tariff calculations are not available for this purpose either.

Accordingly, in the initial stages of a market in the particular circumstances of the Territory, bid price restrictions will be a more pragmatic and simple means of controlling the potential market power of PWC generation and are recommended.

In the draft report we noted this approach may be contentious and emphasise that it does not explicitly ensure PWC generation will offer contract cover for times when a new entrant generator is out of service. Where comment was made about this area, submissions generally supported cost based pricing subject to other parts of the design, in particular the RAM, providing the necessary revenue to meet total costs for efficient level of capacity. Cost based pricing limits the potential price in the real time market, which as noted is expected to fall in a relatively narrow range given the fuel and technology portfolio in the Territory. Finally, as a government owned business, there will be an implied threat of a government requirement being imposed at a later time that could require PWC generation to stand in the market in a similar way to the requirement in Tasmania and more recently in the UK.¹⁴ Conversely the restriction on prices in submissions can be relaxed or otherwise amended readily in the light of experience.

5.6. Real time price, ancillary services, constraints and gate closure

The effect of the detailed design for real time energy price, ancillary services, constraints and gate closure are interrelated and best considered as a package. The following discusses issues around each and then draws them together in section 5.10 after consideration of ancillary services, transmission losses and market prudential requirements.

13 See: [http://www.treasury.tas.gov.au/domino/dtf/dtf.nsf/LookupFiles/Electricity-Reform-Report.pdf/\\$file/Electricity-Reform-Report.pdf](http://www.treasury.tas.gov.au/domino/dtf/dtf.nsf/LookupFiles/Electricity-Reform-Report.pdf/$file/Electricity-Reform-Report.pdf)

14 See https://www.ofgem.gov.uk/press-releases/ofgem-tears-down-barriers-competition-bear-down-hard-possible-energy-prices?utm_source=Ofgem+Website+Mailing+List&utm_campaign=6396e4daa3-Ofgem_Email_Alert2_26_2014&utm_medium=email&utm_term=0_a9e586c268-6396e4daa3-376756233

5.6.1. Gate closure considerations

Gate closure is the period of time before dispatch that generators may resubmit commercially sensitive information to the dispatch process of a market. Gate closure in international markets varies from a number of hours down to a few minutes. For example: gate closure time in the WA WEM and elsewhere is 2 hours and approximately 3 minutes within the NEM 5 minute dispatch cycle. The commercial significance of gate closure time depends on the details of a market design and the logistical capability of IT infrastructure.

Under current arrangements between the System Controller and PWC Generation the gate closure time is effectively zero as the System Controller and PWC Generation continue to liaise until the time of dispatch. But the submission process is internal to PWC and not intended to be independent. In a market setting the processes used in determining dispatch must be robust and transparent and there will be practical limitations as to how close to the time of dispatch submission can occur. Information about physical changes to plant must continue up to the time of dispatch in order to allow the safe operation of the power system but commercial matters such as price can be locked in earlier. It is for this reason gate closure is primarily a market concept. Fit for purpose procedures and IT systems will be needed to replace the current informal arrangements. To the extent the systems are specific to the Territory, specifications for these arrangements should avoid over-design in order to avoid unnecessarily high costs which may be proportionately reasonable in larger markets. Access to the systems of AEMO and or WA IMO may also be a means to manage costs. These are matters that will need to be considered carefully in the implementation stages.

5.6.2. Real time energy market price considerations

Real time prices can be calculated in a number of ways: for example from real time dispatch *instruction* or real time dispatch *outcome*. Both approaches are used in different markets, for example the Spot Price in the NEM is based on dispatch instruction but the WA WEM balancing price is based on outcome but is part of a design with a formal day ahead short term energy market (STEM). Both approaches are workable providing other detailed aspects of pricing and settlement are consistent with the approach chosen.

A price based on instruction is calculated on the System Controller's expectation and latest information about conditions just prior to the System Controller issuing dispatch instructions. A price based on outcome effectively reassesses what instruction and hence marginal price would have been had the Controller had perfect foresight about customer demand and generator capability.

Both approaches have practical advantages and disadvantages. Calculation of real time price from instruction is simple providing the basis for the instruction is captured in data files. The calculation can be done immediately. Calculation on the basis of outcome requires a reconstruction of dispatch, but data is always available, but possibly with a delay. Price on the basis of outcome requires a knowledge of the instructions issued by the System Controller for example to distinguish between situations where a generator has not generated to its full capacity at a given price point because the capability of the generator was less than expected and where the System Controller instructed the unit to hold below full capacity due to a security constraint.

Real time pricing can also be based on *energy* over the relevant dispatch or settlement time period or a *snapshot* value at some point in the period, for example the start, mid point or end.

For the foreseeable future the real time price in the Territory is likely to fall in a relatively narrow range given the proposed cost based pricing requirement and similar fuel and generating technologies. As a result the difference between the approaches is likely to be less than in other markets with a larger spread.

5.6.3. Network access and constrained on/off considerations

This review is primarily about the participation of wholesale generation/ demand side resources. However, access to market is closely linked to investment in, and operation of, networks and limited network access can cause commercial detriment in the energy market.

Generators that are dispatched by the System Controller to an output that is inconsistent with the price they submitted and the real time price are potentially commercially disadvantaged - for example a generator that submits a price for 50MW of output of \$60/MWh and the market price is set at \$70/MWh but is only dispatched to 40MW.

However, if the dispatch to 40MW was because the generator had entered into an ancillary service contract with the System Controller and was being remunerated by that contract it would not be at a disadvantage. Conversely if the dispatch to 40MW was due to a network operating constraint then the generator may be disadvantaged.

Real time electricity markets sometimes include the concept of constrained on and constrained off payments to reconcile disadvantage of this nature but in other cases do not. Many established markets struggle with the coordination of regulated networks and generation/demand side on a competitive basis that give rise to this type of problem.

The NEM is a case in point. The AEMC is currently undertaking a major review (The Transmission Frameworks Review) in this area and is proposing a concept known as Optional Firm Access (OFR) whereby generators/demand side would be able to contract with a network business for a defined level of (financial) access and be compensated if this was not available because other (uncontracted) generators had been dispatched ahead of the contracted generator(s).¹⁵

In part the situation in the NEM is complex because the NEM commenced with multiple generators and “non-firm” access to networks meaning that there was no right to firm access and network businesses have chosen not to offer it voluntarily. The NEM does not provide constrained on/off payments due to network limitations.¹⁶

¹⁵ See <http://www.aemc.gov.au/market-reviews/completed/transmission-frameworks-review.html>

¹⁶ The only situation in which the NEM may provide constrained on/off payments is under market suspension when an administered price is used to set the price see NER cl 3.14.6

The WA WEM approaches access differently. Generators are required to obtain “unconstrained” access for their full capacity and accordingly are generally only subject to network constraint when part of the network is unavailable for maintenance. The WA WEM compensates generators if they are affected by network congestion. The Alberta market in Canada has also had a policy for no congestion under most operating circumstances in order to avoid commercial detriment in their energy market. The “unconstrained” access approach significantly reduces the potential for commercial detriment in the real time market but has been criticised as potentially requiring over-investment in networks. The Economic Regulation Authority in WA has called for the unconstrained approach to be reviewed.¹⁷

The NEM and the WA WEM both assume appropriate payments will occur under ancillary service arrangements and under network support payments written with network businesses without additional payments. Ancillary services are also considered in more detail in section 5.7.

Before leaving this topic it is useful to note that some international markets set a dispatch price at each (transmission) node in the power system (nodal pricing) and others set a nodal price that applies only for generation but load pays a price derived from the average of generator nodal prices. Nodal prices allow the price at each node to reflect prevailing network constraints and is more precise. Neither of the established markets in Australia use nodal dispatch price, although the NEM sets regional prices. In the NEM this has led to a number of situations where prices are distorted when congestion occurs and is a significant reason for the AEMC’s Transmission Frameworks Review. The question of if and how to price network congestion is one of the major questions and trade-offs that need to be made in establishing a competitive market for electricity. The more precise or accurate the pricing is the more complex the design must be. Our expectation is that for the foreseeable future gas fired generation will set the NTEM price most of the time and that as dispatch prices are to be required to reflect cost price differences and therefore any “mis-pricing” that occurs, for example during network outages, will be relatively small compared to other markets - however this is a judgement and we have not undertaken quantitative analysis in this regard within the timeframe and scope of this work. For this reason and because a nodal solution would be unique to the NTEM within Australia we do not consider nodal pricing to be warranted, especially for the start of the NTEM.

Only one submission to the draft discussed this area and included a suggestion that nodal pricing be considered and that it would improve dispatch efficiency. Given that dispatch is to be based on cost we do not expect dispatch efficiency to be dependent on how price is set - which it might be if dispatch submissions it were price-based as it is in the NEM and participants reacted to expectations of inefficient prices. The submission also notes that full Locational Marginal Price (LMP) is paid in the NZ electricity market. However, we are aware that after an extended period of design a Financial Transmission Rights (FTRs) market was introduced in the NZ market in 2013.

By definition, regardless of the pricing mechanism, the unavoidable consequence of congestion is that the output of one or more generator(s) will be limited by the dispatch process. The pricing mechanism determines how much they are paid from the market for the reduced volume.

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See - <http://www.erawa.com.au/cproot/10372/2/20120514%202011%20Annual%20WEM%20Report%20for%20the%20Minister%20for%20Energy%20-%20Public%20Version.pdf>

Mechanisms such as FTRs and OFA style arrangements provide different forms of financial adjustment for the consequences of reduced output and in some arrangements, insurance for customers about the net price they will pay for electricity. These considerations highlight the potential complexity that can be introduced.

On balance, for the reasons discussed above, we have recommended a simple single region price approach for the NTEM. We do this expecting that the commercial impact of congestion will be limited by the expected limited difference in prices when congestion leads to limits on operation of one gas plant but it is replaced by another gas plant elsewhere in the system. The trade-off for this simplicity is that there will be some exposure of generators to price differences. This type of exposure has existed in the NEM since it was launched (notwithstanding that the price based dispatch has led to high commercial exposure and dispatch inefficiency and is now being addressed by the AEMC) and in the WA WEM. As noted earlier, the option of constrained on/off payments can be revisited if appropriate.

5.6.4. Intervention considerations

In the event of a threat to reliability of supply or other emergency, market rules typically give the System Controller power to intervene to “do what is needed”. Interventions can distort market price outcomes, typically lowering the real time price. In an energy-only market lower prices due to intervention are often heavily criticised as blunting the very signal that was intended to incentivise additional capacity to avert the problem in the future. In these situations, if price were to be suppressed it would risk a downward spiral of investment and consequentially an increasing spiral of occasions when intervention is necessary - exactly the opposite of the intention of a market. In recognition of this concern the NEM includes special provisions to ensure the real time price is set as if the intervention had not occurred to avoid the problem.

Intervention in the WA WEM does not affect the operation of the Reserve Capacity Mechanism and intervention if required is of less significance in the real time (balancing) market as it relates to operational cost only and no equivalent measures to adjust price are included in the market.

Similarly no provision is considered necessary in the proposed NTEM.

5.6.5. Price caps and supply shortfall considerations

Supply shortfalls can occur for two main reasons. If there is insufficient generation, for example due to simultaneous breakdown of generation the System Controller must curtail customer demand to match the available supply. Secondly customer demand may be interrupted by failure of transmission or distribution lines for example due to storm activity.

The effect of generation shortfalls should be reflected in the real time price, which should be high at these times. No special provisions are warranted to avoid high prices per se. Note, the Cumulative Price Threshold (CPT) provisions of the NEM cap the Spot Price if extreme prices exist for an extended period. The CPT is designed to limit exposure to the cumulative effect of prices that are expected to occur for only short periods over peak demand times, but because of the prevailing circumstances extend for far longer. No similar arrangement would be warranted in the design proposed for the NTEM as the RAM is designed to provide the incentive and pricing for investment in a similar way to the Reserve Capacity Mechanism in the WA WEM.

Transmission related incidents may force the disconnection of both generation and demand and also cause parts of a network to separate into “islands”. Generators with a contract obligation may be prevented from operating in part or in full at these times and be commercially impacted. It is useful to note that retailers may realise a windfall gain in these circumstances if the loss of customer load leaves a retailer over contracted. The retailer’s gain will be at the expense of a windfall loss to generators.

As major storm activity is common in the Territory, the market rules and contract terms and conditions should consider how this type of situation is to be managed. The NEM suspends the market when AEMO determines it cannot operate the market in accordance with the NER. This topic will require further work during detailed implementation, it may be appropriate for the market to be suspended at these times.

One submission noted the potential for adverse commercial impact of price outcomes associated with storm activity and was concerned about whether operation of the RAM would be distorted as a result. We agree in principle about there being a risk but expect this matter to be considered during the detailed design process.

5.7. Ancillary Services

Ancillary services are essential to the viable operation of a power system and are needed because of the technical requirement for supply to match demand on a minute by minute basis.

The three most common ancillary services assist in managing power system frequency, power system voltage and recovery from situations where all or part of the generating fleet has shut down due to a system wide disturbance. The precise definition of each of these ancillary services varies. Other services are sometimes grouped with them: for example where a generator or customer is contracted to alter production or consumption to manage loading on a transmission or distribution network this can be termed an ancillary service or a network service.

Ancillary services are relevant to design of a wholesale electricity market as deployment of services may impact how generators are dispatched and therefore the price in the market. For example: in order to provide an ancillary service a generator may be required to operate at a different level than it would otherwise and this may affect its commercial return. As supply must match demand at all times, where one generator is required to operate higher, another must be operating lower. As a result generators not involved in supplying ancillary services at the time may be affected but will be benefiting from the presence of the service facilitating functioning of the power system.

In practice ancillary services to manage power system frequency have the most impact on production of energy and are also the services most readily determined on a joint basis with energy using similar sets of cost/price bids to energy - in a co-optimised dispatch process. However, the dispatch process in a market must be transparent and co-optimised energy and ancillary services in a robust and transparent market process is more complex and costly. Therefore many markets use a contract based approach for all ancillary services with rules for how the System Controller should use the contracted capability accompanied by appropriate pricing. It is notable that the NEM commenced with a contract approach and moved to a co-optimised approach after a number of years and the WA WEM uses a contract approach linked but not co-optimised with dispatch.

Ancillary services are generally a small percentage of total industry costs and it is important therefore to ensure time and effort to optimise their use is proportionate to the likely benefits. Accordingly, an electricity market design should ensure the dispatch process is cost effective and that the resultant market pricing and allocation of costs are internally consistent.

A cost-benefit analysis of the potential to use a co-optimised energy and ancillary services approach has not been undertaken as part of this review. However, we are not proposing a process for energy dispatch that will accommodate co-optimised dispatch of ancillary services and accordingly propose that all ancillary services be incorporated on a contract basis with consequential market pricing and cost allocation. Use of a contract approach does not preclude a future shift to a co-optimised approach. A number of submissions to the draft supported contract based approach and none opposed it.

5.8. Accounting for losses

Electrical losses are incurred in transporting power within networks. Network construction and distance are two key factors that determine how much loss occurs. Real time or balancing price is designed to reflect the change in the cost of production due to a change in demand, that is, the marginal cost of supply. Scheduled facilities provide their marginal costs at their point of connection. To accurately reflect the effect of consequential change in system wide loss due to change in generation or demand it is necessary to also account for the marginal change in loss.

Marginal losses are typically accounted for as a loss factor that can scale the marginal cost of generation or demand up or down to determine the order in which scheduled facilities should be dispatched. This process provides a means to compare prices from various parts of the network on a like for like basis.

Physical dispatch and settlement for production and consumption occurs on the basis of actual flows at the marginal price of the point of production or consumption. The WA WEM and NEM operate on this basis which is also similar to a range of international markets.

Under the single market real time reference price proposed for the NTEM the effective price at each generator and each point of consumption will vary from the market reference price by the marginal loss factor for each location. This approach to settlement makes generators accountable for marginal losses to the reference point for the market and customers responsible for losses from there to their connection point.

The surplus funds that accumulate in the settlement system due to collection from customers at the marginal price at their connection point but payment to generators at their marginal price is typically paid to the network business and used to reduce total network charges under supervision of the network regulator.¹⁸

The NER and WA WEM rules each provide guidance on the principles for the detailed calculation to determine marginal loss factors which can be adapted for use in the NTEM.

5.9. Prudential requirements

Wholesale customers purchasing energy in the real time market will be debtors to the market operator and the market operator will be a debtor to generators who produced the energy. Notwithstanding that the provision is not being used at present, this is a similar position to that of parties that might be involved in out of balance transactions under the current SCTC. The existing Retail Supply Code includes provisions relating to prudential guarantees for transactions between Generators and Retailers and for network charges.

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A surplus accrues as marginal losses are typically higher than actual or average losses

In order to avoid exposing the market operator to financial risk, markets typically require that the market operator is obliged to pay generators only to the extent it receives funds. However, as markets for real time trading are blind in the sense that generators cannot assess the credit worthiness of the individual wholesale customers, the customers are therefore required to submit prudential guarantees.

Guarantees incur costs and there is therefore benefit in keeping the level of guarantee as low as is commercially responsible. The level of guarantee is generally related to a forecast of amounts likely to be owed which in turn is related to the settlement and payment periods. The final level should be developed in line with standard commercial practices on the basis of relevant expert advice. The NEM and the WA WEM rules each provide guidance on these matters and as noted there is a body of expertise in the Territory as prudential guarantees are already part of the Retail Supply Code.

The proposal for the NTEM is to facilitate optional net settlement of real time trades. One advantage of net settlement is a reduction in the real time settlement amount. However, this reduction is at the expense of an increase in bilateral settlement and credit risk which must be managed by the individual parties.

Net settlement adds some complexity to the settlement arrangements although there is wide experience in this area. Net settlement is a standard feature of the WA WEM as submission of contract positions is mandatory in that market. The NEM uses a concept known as reallocation where a generator and wholesale customer may make a joint submission to AEMO that results in a reduction of the obligation of the customer to pay AEMO for energy consumed in the Spot Market and an offsetting reduction owed to the relevant generator.

As the NTEM is expected to open with very few participants on either side of the market net settlement should be relatively simple to implement and over time additional systems and processes established.

5.10. Energy and ancillary service pricing conclusions and implications

Economic efficiency requires that the real time price be a valid representation of the marginal cost of supply at the time. Commercial viability requires that the package of prices and adjustments are clear, transparently calculated and equitable.

In practice the package can often be a compromise. For example in the NEM the 5 minute dispatch process may call on fast response generators for only part of a 30 minute settlement period and deliver a price over the 30 minutes that was less than the price of generators used within one or two five minute periods and it also can constrain a generator's output due to a network limitation without compensation. In the WA WEM dispatch of energy is not optimised with the cost of ancillary services but it does include a payment when generation is constrained due to network limits.

For the purposes of this stage of review and working with the NEM as the template, the following arrangements are recommended:

- Commercial gate closure two hours ahead of dispatch;
- Security constrained, ex ante price determined one hour ahead of dispatch;
- Ancillary Service by contract - no adjustment to payment within the energy market settlement (implies contained within the AS contract);
- Network Support contracts with network operator for expected network constraints; and
- No constrained on/off for unexpected constraints

Each of the time periods should be reviewed during implementation and moved closer to time of dispatch if practicable or further out if the nominated times create logistical problems in the short term.

The gate closure times will require processes and resources within both PWC Generation and System Controller function including some degree of software support and data logging of decisions.

The absence of constrained on/off payments implies the terms and conditions of ancillary service and network support agreements are developed with this in mind.

The discussion of the issues with various elements of the pricing arrangement is designed to highlight the nature of the trade offs inherent in this area of design. Stakeholders are likely to seek to remove risk or uncertainty in their positions and this is understandable. However, we note that greater precision in pricing generally requires higher complexity in either the dispatch or settlement stages, or both. Greater complexity comes at a cost. The recommended approach is relatively simple and designed to focus on key drivers for efficiency.

6. Transparency, confidence and accountability: the role of procedures and information

This section expands on a section in the draft report that dealt only with publication of energy trading information. The section briefly notes the impact of competitive markets for electricity in the broader economic environment as a precursor to discussion of the role of reporting and information on both energy trading and more general market and technical performance.

External investors in the electricity sector will naturally seek information to assess the likelihood of making a profitable investment. Governments also will naturally look to demonstrate that the electricity sector in their jurisdiction is efficient, reliable and operated to industry best practice and therefore likely to attract investment in the sector and in the economy generally. One reason for organising the electricity sector in an open and competitive manner is to demonstrate these characteristics and allow comparisons with international peers and competitor locations.

The majority of the review and recommendations to this point have dealt with the design of trading and investment activities to achieve efficient and reliable outcomes using competitive mechanisms. Elsewhere competitive markets generally involve publication of an extensive amount of data and information. The full list of material to be published is an item best addressed during detailed design stage although Section 6.1 below discusses two potentially contentious areas which may involve policy decisions.

In addition to quantitative reporting requirements for analysis and informed reporting on the performance of the market and of the power system also contribute to meeting the broader objectives for credibility as a destination for investment and operational performance. These are discussed in section 6.2.

6.1. Data

Historical information about the operation of the market and also from forecasts prepared by entities such as the System Controller are important inputs to the decisions market players must make. All competitive markets publish extensive historical and forecast information such as total demand, market price and output of individual generation plants. We have not included a detailed list of suggested items of information in this report but will make comment on two matters which may be contentious. We expect they will be subjects for detailed consideration in the development of rules as it may not be appropriate to adopt the provisions of another market in whole.

The first area for comment concerns the timing of release of price and volumes in submissions to dispatch. Concern is often raised that such information should only be released well after the event in order to prevent “signalling” between generators that can be used to exercise market power.

The second matter is the broader commercial consequence of creating and publishing a real time price at all. Market price is the foundation of any market and there should be no question that the price should be released. However, in the context of the Northern Territory fuel supply and industry structure, a real time price will be easily used to compute a very good approximation of the price of gas. The recommended requirement that price submissions be cost reflective will compound this situation.

However, if this requirement did not exist, away from peak times it is reasonable to expect that prices will be related to incremental cost and the same conclusion reached. All generators may have concern about this position, but it is an unavoidable consequence and is raised here to ensure the situation is appreciated. In this respect it should also be noted that similar calculations are often made in the NEM where prices are not required to match costs per se and in the WA WEM where they are.

The draft report proposed carrying over the information requirements from the NEM subject to stakeholder input. No submissions questioned this approach and accordingly it is recommended as the basis to move forward to implementation.

6.2. Analysis and reporting on performance

In competitive markets it is usual for entities such as the System Controller and Network businesses involved in the physical operation of the power system to be required to undertake and publish analysis on the operation of the power system, generating plant and own their own performance. Information relating to significant events, in particular where involuntary interruption of customers has occurred is a key component of the suite of reports. Similar reports on significant market outcomes may also be required.

In the context of the three Territory networks, each is small compared with power systems elsewhere with relatively few individual generators, transmission and distribution assets.¹⁹ As a result the Territory's power systems are relatively susceptible to disturbances affecting a single element on the power system compared to other systems. Therefore proportionally higher levels of spinning reserve are required to maintain a given level of performance or more variable voltages and frequency and possibly greater risk of interruption must be accepted compared to larger systems.²⁰ In addition, the Darwin-Katherine region in particular experiences extreme weather events which can also lead to interruptions in supply.

Reduction in the number and severity of interruptions due to disturbances may therefore have significantly more benefit in the power systems of the Territory than other systems. On the other hand, openness about reporting on instances and importantly the reasons for interruptions that do occur will enhance credibility. As a result requirements for analysis and reporting in line with industry best practice to demonstrate compliance and a focus on reducing the incidence of interruptions are to be encouraged. The NER (recommended as the template for the NTEM rules) has comprehensive reporting and analysis requirements and provides a benchmark for best practice. The NER provisions should be adopted in principle but reviewed to ensure that factors such as thresholds for reporting remain appropriate.

7. Asset values and community service obligations

The amount of capacity called for under tender in the Reliability Assurance Mechanism may be less than the total offered or is present now. As a result some capacity may be financially stranded without a RAM contract. That capacity would be free to participate in the real time trading process but will not receive revenue from the Reliability Manager. Any capacity affected this way will suffer loss of asset value.

It will be a matter of policy for government as to how any stranding may affect the current Community Service Obligation Payment that is needed to meet full operating costs of PWC with the current tariff level.

8. Opportunity for demand side participation

Participation in the RAM will be open to demand side resources which have suitable guarantee of delivery. We note there is strong demand side participation in the WA WEM Reserve Capacity Mechanism which has similar performance requirements to those envisaged for the RAM. However, it is recognised that the WA WEM mechanism does not reduce the price paid for capacity once the minimum requirement has been met sufficiently to avoid creating an over supply situation. The RAM would be designed so that (inefficient) over supply did not emerge due to the operation of the RAM.

Participation would also be open to demand side in the ancillary services arrangements which is the dominant mechanism for demand side participation in the New Zealand electricity market.

19 The open cycle gas turbine technology used in many of the generating units has inherently lower inertia than other technologies and this increases the susceptibility to some types of disturbance.

20 This situation is common to all power systems - for example prior to interconnection both the South Australian and Tasmanian systems were more susceptible to disturbances and operated with wider performance standards. The NEM power system security standards include wider standards for any parts of the NEM that become electrically islanded from the rest.

Demand side may have a role to play as a substitute for diesel plant in the real time energy market, however, we would expect the main avenues for participation will be through the RAM and ancillary services.

9. Opportunity for renewable resource participation

The proposed design is intended to be “indifferent” to the technology of generation resources - that is no technology should be at a relative advantage or disadvantage over another. In practice this can be difficult to achieve and inadvertent priority or barriers can emerge due to factors such as the design of technical standards for the connection of equipment or the timescale of payments. While the design of wholesale market trading arrangements is important, renewable technologies are often affected by the combined operation of: network pricing and access arrangements; ancillary services; energy payments; capacity payments; the allocation of effective capacity rating (in the RAM); technical standards and the implementation of external policy initiatives. Attention is required to each of these areas during implementation. The following presents brief comment on three such considerations.

The first is that barriers can be minimised if technical standards are drafted as output service or performance requirements instead of input design requirements: an example of performance requirement is a specification that generator output does not fall during a technical disturbance on the power system but not specify how that is achieved. Similarly, renewable resources are more likely to employ newer and different technologies than traditional plant as well as being less conducive to close second by second control of dispatch by the System Controller - the most well known example being wind generation that is inherently intermittent. Modern power systems and market designs accommodate these characteristics, some better than others.

The second consideration is that technical integration of renewable technologies into the short term operation of a power system should be seen as a different matter to implementation of policy initiatives. If technical requirements are expressed as performance requirements and costs for ancillary services are allocated efficiently, a wide range of generating technologies can be accommodated. However, where a policy is designed to ensure specific technologies or groups of technologies are subsidised to enter the market the design of the policy can make a major difference to the credibility of the market and whether it achieves its broader objectives. For example the impact of construction of subsidised renewable technology in response to a renewable target is significantly different if the requirement is for less than the new investment in capacity required to meet demand than if it is more. When the requirement is less than the total new investment it takes market share from new entrants, but if the requirement is higher it will take market share from incumbent plant and thus strand the incumbent plant. From a policy perspective stranding is not a concern in itself as a role of a market is to facilitate entry of newer and better technologies. However, where stranding occurs only as a result of a subsidy there are major policy considerations. Our view is that any competitive market can be adversely impacted in this way but a market with a separate capacity mechanism such as the proposed RAM is likely to be affected less. Similar issues arise with other policy initiatives including energy efficiency. In short there are “good and not so good” ways to introduce policy into the electricity sector when it is operating as a competitive market.

Thirdly, many renewable resources are small scale and often embedded in, or close to, customer connection points and are more affected by regulatory provisions relating to regulated networks than larger scale generation facilities. Accordingly proportionally greater attention is required to coordinate the operation of regulated and competitive rules and regulations - this is a current area of focus for market authorities in Australia and internationally.

10. Industry governance and structure

10.1. Introduction

A competitive and disaggregated market for wholesale electricity requires a disaggregated management and governance infrastructure comprising a number of governance instruments and functions. A number of functions are self evident commercial participants or asset and service providers such as networks and include generators, network operators, retailers, ancillary service providers and metering bodies. Others are central or special purpose market functions, some of which can be remotely located. For practical and cost management purposes it is common for a number of the central functions be grouped and undertaken by a limited number of entities, thus reducing overheads and complexity. Grouping the functions also requires fewer individuals with the requisite knowledge and skills but risks introducing risk of perception of conflict(s) of interest and lack of independence. Design of the governance arrangement therefore involves trade-offs.

10.1.1. Functional separation

Before describing our recommendation in relation to the allocation of roles for the central market functions it is important to note that in developing the strategic direction and detailed design elements we have presumed a number of structural changes occur to the current industry structure. These are important and are noted again for emphasis and include:

- The proposed separation of PWC generation from other parts of the corporation is completed as planned;
- PWC gas will also be structurally separated from PWC Generation to allow it to function as a neutral Gas Supplier/Trader offering fuel to any party on an equal footing. The reason for this is that in our experience independence of fuel supply is a forgotten pre condition for independent generation. As PWC currently holds contracts for very significant quantities of gas likely to be needed over the medium term it will be an obvious potential supplier to new entrants. PWC gas should therefore act and be seen to act independently;
- Every effort to demonstrate the independence of the System Controller/Market Operator function will proceed - erring on the side of greater rather than less independence. Note that although the System Controller and Market Operator roles are separated in some markets this is not a requirement or natural outcome of our recommended design. A single body is clearly less costly as well and avoids the need for rules relating to overlapping decisions and passing information between separate bodies.

There is an argument that PWC Networks should be separate from the System Controller function, but this is less important. The reason for this is that while the System Controller's decisions are generally related to choices between generators, occasionally the choice can be between generation and networks: for example how a security constraint will be applied may impact a network's regulatory performance incentives or constrain a generator and impact its commercial returns. However, these occasions are generally infrequent and separate bodies mean additional cost and resources. Accordingly we have assumed the risk of such conflict will be addressed in the rules and procedures of the market rather than through structure.

Key central roles and recommendations for allocation of responsibilities are listed in Table 1.

Table 1 Allocation of key governance and administrative functions

Role or function	Description	Structure and allocation
Market Operator	Manages registration, prudential assessment, settlement and metering	Independent special purpose role within PWC corporate market group. Closely linked to System Controller. Options to utilise process and systems of other market operators - detailed arrangements should be integrated with final arrangements for System Control
System Controller	Two primary roles On shift role - manages real time power system operation, receiving amended submissions after gate closure for real time market submissions, and real time dispatch Off line role - manages pre dispatch (unless automated and fully managed by on-shift). Assesses generator maintenance Third possible role - overlaps with network planning System incident analysis and reporting	Independent System Controller within PWC corporate - Closely linked to market operator. Options to utilise processes and system of other System Controller - especially for off line activities Allocation determined mainly by resource expertise and costs. Requires relevant technical expertise within System Control/Networks or external parties with access to full data and to relevant parties in NT
Reliability Manager	Manages Reliability Assurance tenders and contracts	Independent special purpose role within PWC corporate market group. Closely linked to Market Operator Option to use suitably expert external assistance in one or both of technical analysis or requirements and of tendering
Economic Regulator	Economic regulator of networks	Proposed transfer to AER (government policy)
Surveillance, monitoring and enforcement	Monitoring of performance and behaviour of RAM and real time market	Consider transfer to AER. Cost may be an issue. A question re enforcement authority, does this transfer too?
Gas Supplier/Trader	Neutral intermediary for large scale gas contract	Independent special purpose role within PWC corporate market group. Closely linked to Market Operator - must be functionally separate from generation
Market rule maker	Power to make and amend market rules	Warrants detailed consideration.

and standard setting	and set technical standards	Option to transfer to rule making to AEMC. Also consider an NT Panel similar in concept to Reliability Panel with NT policy membership/expertise.
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10.2. Governance instruments

10.2.1. Legislation

We have assumed legislation will be a matter for government to determine

10.2.2. Rules

Having established that the NER can form a template for the NTEM we have reviewed the relevant sections of the NER and noted the high level range of changes that will be required - see Appendix D. This review was unavoidably high level in the time available.

We have also noted (see section 11.1) the opportunity for minor amendment to the existing SCTC as the basis for an interim market with far less effort and cost.

10.2.3. Standards

Generation reliability standards

Section 5.2.1 discussed generation reliability standards in the context of the role of the Reliability Manager. Similar comments about the formation of a reliability standard would apply under any approach to assuring or monitoring generational reliability. In the WA WEM the form and level of reliability standard is specified in the respective market rules. In the NEM, under the NER both the form and level are recommended to the AMEC by a Reliability Panel.

From experience we consider that the size and technical characteristics of the Northern Territory power systems may mean that the most appropriate form of reliability standard may differ from that used in the NEM or the WA WEM. In our concluding comments to section 5.2.1 we noted that there are policy considerations in the choice of the form of reliability standard. Accordingly government (as policy maker) should be conscious of choice about the measure for reliability and the accountability implication of where the decision making role sits for setting the generation reliability standard. That said, the NEM Reliability Panel has considerable experience in reviewing generation reliability standards and it may therefore be appropriate for it to take some role in this regard. Similarly the IMO in the WA WEM has responsibility under the WA WEM rules for determining the standard in that market and also has experience in this regard.

Technical standards

Establishing market arrangements highlights the distinction between which features and characteristics of the network, connected generators and connected loads are explicitly and commercially accounted and which are mandated and can be thought of as a cost of doing business. Market arrangements often spend considerable time debating this area.

If the NER is adopted as the template for NTEM Rules technical standards for connected plant will be covered by the NER approach which is based on the concept of System Standards and Plant Standards. System standards set out the standards a party can expect from the performance of the power system and therefore what their plant will need to accommodate - for example the level of harmonics or voltage flicker. Plant standards define the performance of individual items of plant and therefore the impact they may have on the power system. Within this framework the NER also includes some flexibility including use of standards for automatic approval and a lower minimum performance level.

Our expectation is that while the framework will undoubtedly work, the levels of performance may not be cost effective for the smaller power system and would need review. We also note that, subject to review, the parameters in the existing Technical Code may be able to be translated to the NER framework to create a consistent regulatory document but with detailed technical levels appropriate to local conditions.

11. Implementation, transition and next steps

Functional separation of an integrated utility and introduction of competitive market arrangements each require that existing operational and management relationships are formalised and commercialised. Generally new processes are required as well. In our experience there are many and varied activities that need to be coordinated and a dedicated project team approach with representation from key affected groups is valuable. As the changes can have a significant impact on the strategic and operational activities of different parts of the organisations clear top management involvement and endorsement is essential.

The following lists a number of activities that are crucial to implementation of the proposals recommended in this report.

In addition to the proposed structural reform of PWC to separate PWC electricity retail and PWC Generation from the System Controller and PWC Networks, the proposed arrangements for the NTEM will require organisational arrangements to:

- Create the Reliability Manager;
- Create an independent Market Operator function;
- Create/re-enforce the independence of the System Controller; and
- Create a clearly separate and independent Gas Trader
- Ensure relevant staff in Generators, Retailers and the Reliability Manager are trained and accredited for trading and contracting activities. Accreditation will include for financial trading.

In addition to the proposal to transfer network regulation to the AER, governance arrangements will be needed to:

- Establish and manage market rules;
- Establish or incorporate within the market rules or associate procedures, provisions relating to:
 - Technical
 - Supply Reliability standards (against which the Reliability Manager will acquire capacity in the Reliability Assurance Mechanism);
 - System performance standards (possibly unchanged from current)

- Connection/plant performance standards (possibly unchanged from current)
- Metering (possibly unchanged from current)
- Commercial/market
 - Prudential processes and assessment details
 - Settlement and Treasury processes
 - Metering procedures (e.g. acquisition, storage, error correction);
- Establish Ancillary Service contracts - consistent with design of real time energy pricing and dispatch, system and plant performance standards; and
- Establish network support contracts consistent with design of real time energy pricing and dispatch, system and plant performance standards.

If the NER (or other existing market rules) were adopted as a template as a means to reduce the time and effort in producing market rules for the NTEM, sufficient time and resources would need to be devoted to working through each of the provisions to examine applicability and whether amendments are required for application to the NTEM. The two Australian templates are the NER and market rules of the WA WEM. Both of these are lengthy documents covering hundreds of pages and each has legal standing. If similar consultation periods were to be followed a minimum of 12 months plus consultation time should be allowed and even then this would require a focussed team to review and develop changes.

We note that the set up for the Reliability Manager will involve similar calculations to those that would be required for any form of capacity market. If the alternative of an integrated energy only market design, such as the NEM, were to be adopted, it would be necessary to set up initial risk management contracts and processes which would provide commercial stability and be designed to manage market power of the dominant PWC.

11.1. Interim implementation option

We note the prospect of an interim or internal market trial based on relatively minor amendments to the existing SCTC, Network Technical Code and the Retail Supply Code to allow the basic elements of the energy trading arrangements we have recommended to operate. Note, this does not include the Reliability Assurance Mechanism and thus it is not a complete market package.

In more detail: clause 5 of the SCTC currently allows for an independent third party generator to wheel energy through the PWC network to an associated customer. Clause 5 also requires that the generator and customer self-balance, that is that the generation must be varied to suit the customer demand inclusive of (actual) network losses. Clause 5 also recognises that the self-balancing will be imperfect and requires other generators provide out of balance buy and sell bids and that the System Controller should determine out of balance buy and sell prices based on the lowest and highest out of balance bids respectively that are dispatched, i.e. marginal prices for buy and sell.

The energy trading arrangements proposed for NTEM differ in that there is no requirement for self-balancing and the out of balance prices are replaced by prices for the full operating range of all generators and a single real time price accounting for marginal losses is set for the market. However, the mechanics and principles are similar.

The existing arrangements are not designed to manage investment or accommodate generators or customers selling and buying from a competitive market, but the basic framework for real time energy trading is available with the amendments as noted and provides a starting point.

In addition to arrangements related to reform the structure of PWC and establish future arrangements for network regulation the main areas of work will be required to implement the proposed competitive arrangements are:

- Develop regulatory instruments, in particular the market rules;
- Establish and implement registration requirements;
- Establish the Reliability Assurance Mechanism including:
 - Defining the standard for generation reliability
 - Setting the parameters for payment.

We note that similar calculations would be required for any form of capacity market. If the alternative approach of an integrated energy only market design, such as the NEM, were to be adopted, it would be necessary to set up initial risk management contracts and processes which would provide commercial stability and be designed to manage market power of the dominant PWC;

- Establish transparent daily processes for PWC Generation (and in time any new entrants) to make daily submissions for dispatch and System Controller to prepare dispatch plans;
- Establish transparent processes to determine real time energy prices; and
- Establish a settlement processes for real time energy transactions;

We consider informal interim arrangements for day to day operation could be developed readily based on targeted amendment of the existing regulatory instruments such as the System Control Technical Code and the Retail Supply Code. Clearly these would be bespoke arrangements for the Northern Territory. The arrangements we envisage would not be suitable for long term operation or for commercial participation of external parties unless they explicitly accepted the informality. With a focussed effort we consider that informal arrangements could be established in around three months. They could form a prototyping and training platform but would also result in more robust and transparent day to day operations than is possible under current circumstances.

A minimum of 12 months plus consultation time would be required to establish a minimum set of formal arrangements although these times may be significantly longer depending on the level of effort and external interactions and processes to enlist external assistance. Choices and conditions about timing of handover of regulatory or operational processes to external parties may also influence the time for implementation.

Experience shows that changing arrangements with commercial implications after the fact can be fraught. For this reason to the extent that interim arrangements do not reflect longer term objectives, for example to use the NEM (or other market) as the template for market rules, it should be clear to new entrants what the longer term objectives are from the start.

Appendix A Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
NEM	National Electricity Market
NER	National Electricity Rules
NTEM	Northern Territory Electricity Market
PWC	Power and Water Corporation
SCTC	System Control Technical Code
WA WEM	Western Australian Energy Market

Appendix B Terms of reference

The consultant should consider the applicability of the NEM model to the Territory. The consultant should also provide a high level comparison of other wholesale market designs, including the SWIS, to the NEM and whether other market arrangements would better suit the Territory's regulatory reforms.

The consultant is to consider wholesale electricity market arrangements that are suited to the Territory's circumstances and capable of cost effectively replacing reliance on bilateral contracting.

In recommending an appropriate market design, the consultant should consider the application of the following arrangements to the Territory (but not limited to):

- To recommend appropriate wholesale electricity market arrangements for the Territory. In making a recommendation the consultant should address (but not be limited to):
 - Application of the relevant generation components of the National Electricity Rules to the Territory;
 - Arrangements for determining energy pricing, supply availability and trading processes (including market settlements and prudentials);
 - Arrangement for economic dispatch and associated rules;
 - Responsibility and market trading processes for ancillary services to manage short and medium-term electricity supply stability;
 - Arrangement for determining marginal loss factors; and
 - Relevant generation technical parameters to ensure generation availability and energy supply standards that are consistent with good industry practice.
- The recommendations should be informed by assessment of the applicability of the NEM model to the Territory and a high level comparison of other market designs including the WA SWIS and whether arrangements other than the NEM would best suit the Territory's regulatory reforms;
- The consultant is to make recommendations on the party/parties best suited to manage the various components of the market design arrangements;
- The consultant is to provide recommendations regarding the design and rules that could be adopted initially in the Darwin-Katherine generation market, and later other markets including Alice Springs; and

In recommending the appropriate wholesale market arrangements, the consultant is to develop the proposed rules in consultation with relevant stakeholders.

Appendix C Current Northern Territory electricity supply arrangements

C.1 The Northern Territory power system

The Northern Territory has three principal electricity networks supplying the Darwin-Katherine, Tennant Creek and Alice Springs networks. The three networks are not interconnected with each other.

The three systems and their generation capacities are shown in Figure 2.

A number of smaller generating systems supply remote communities and some relatively large remote generation systems supplying mines (for example, McArthur River and Groote Eylandt) which are not operated by Power and Water Corporation (PWC).

C.2 Industry Structure

All customers within the Northern Territory are contestable, although a Pricing Order caps the price that may be charged to smaller users.

PWC, a state government owned entity, is the dominant entity in the industry.

PWC is a vertically integrated corporation with separate business units for Generation, Network and Retail. The Gas group is responsible for securing gas supply for Generation.

Generation

PWC accounts for 90 per cent of total generation and the majority of customer load. Five Independent Power Producers operate under contract to PWC and supply power to the Darwin-Katherine and Alice Springs networks.

PWC also supplies electricity to 72 remote communities and 82 outstations under a contract for service model (mainly) with the Northern Territory government²¹.

The portfolio sits within the responsibility of the Minister for Essential Services and is overseen by the shareholding Minister (Treasurer).

IPP's are issued a special licence to operate and there are four non-PWC generators supplying electricity into the Darwin-Katherine and Alice Springs Systems under contract to PWC.

There are three other IPP licences registered supplying remote mine operations and not connected into the above networks²².

Retail

PWC has approximately 72,000 customers. In addition to PWC there are two independent retailers registered. They are:

- QEnergy Limited
- ERM Power Retail Pty Ltd

²¹ Utilities Commission Annual Report 2012-2013, available at www.utilicomm.nt.gov.au

²² Utilities Commission Register of Electricity Licences and Exemptions

C.2.1 Networks

PWC is the only licenced electricity network company in the Northern Territory.

PWC owns and operates the 709 kilometres of transmission system and 7,650 kilometres of distribution system CROSS the 3 main network systems.

The networks performance is regulated by the Utilities Commission under the Standards of Service Code and Guaranteed Service Level Code.

C.2.2 Generation fleet

PWC is the dominant generator in the Northern Territory and within the three main networks, gas is the main fuel with several generators operating with dual fuel (gas and diesel) capability.

Installed capacity Darwin-Katherine System is 468MW, 17 MW installed in the Tennant Creek System and 90MW installed in the Alice Springs System. Further details are shown in Figure 2.

The Darwin-Katherine system uses a mix of simple cycle and combined cycle plant. The majority of simple cycle plants can be fired from gas or diesel. The Tennant Creek and Alice Springs system are comprised of a mix of simple cycle combustion turbines together with diesel and spark fired reciprocating engines using a mix of gas and diesel fuel.

C.2.3 Fuel supply

The primary source of gas is from ENI's offshore Blacktip gas field north-west of Wadeye. The gas is transported into the Amadeus pipeline and distributed north to Darwin and south to Tennant Creek and Alice Springs.

PWC Gas has a long term gas supply agreement with ENI for supply to the generation fleet. The gas is contracted to replace the previous Amadeus Basin gas supply arrangements.

Contingency fuel supply arrangements are in place with Darwin LNG (DLNG) at the Wickham Point connection in the event Blacktip gas is unavailable. Linepack is also a possible contingency provision for short periods.

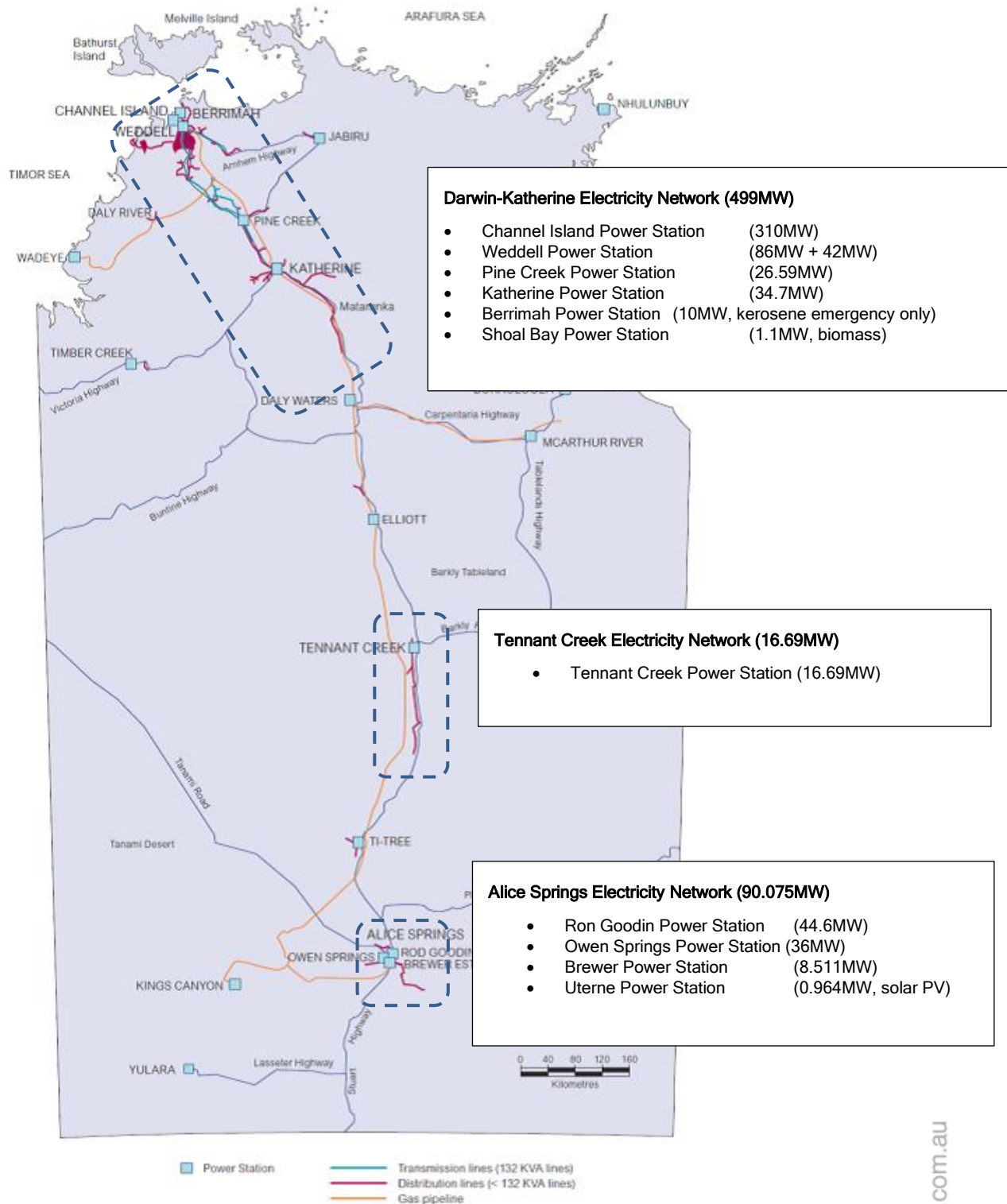
Diesel fuel backup is also available with storage located at most power stations and diesel capacity is able to match peak loads and the ability to supply limited only by the availability of diesel.

Based on forecast system demand profiles, the gas supply arrangements with ENI and contingency provisions are considered adequate²³ (at the exclusion of the provision of gas supply to the Gove refinery, the subject of recent announcements by Rio Tinto²⁴).

²³ Utilities Commission, Power System Review 2011-12, April 2013. Available at <http://www.utilicom.nt.gov.au/PMS/Publications/09042013%202011-12%20Power%20System%20Review%20 MASTER %20FINAL.pdf>

²⁴ Rio Tinto (29 November 2013) [*Rio Tinto to suspend production at Gove alumina refinery*](#)

Figure 2: Northern Territory electricity infrastructure²⁵



²⁵ Utilities Commission, Power System Review 2011-12, April 2013. Available at <http://www.utilicom.nt.gov.au/PMS/Publications/09042013%202011-12%20Power%20System%20Review%20MASTER%20FINAL.pdf> (map), generation data added

C.3 Industry Governance

The Northern Territory electricity system is governed by the Power and Water Corporations Act, the Utilities Commission Act, the Electricity Reform Act and the Electricity Network (Third Party Access) Act, associated regulations and codes.

Utilities Commission

The Utilities Commission is an independent statutory body and regulates the electricity, water and sewerage systems in the Northern Territory.

In addition to its licencing and price regulation functions activities relevant to development of wholesale electricity include its role to approve the System Control Technical Code (SCTC) prepared by PWC and the Network Planning Criteria. These instruments set out the basis under which PWC manages technical operation of the electricity system, generation scheduling, ancillary services and quality of supply standards. The Commission also establishes a Retail Supply Code. One matter covered in the Retail Supply Code deals with prudential requirements for dealings between generators and retailers and also between networks and connected parties.

The Utilities Commission is also the economic regulatory for Networks although the Northern Territory government is proposing the transfer of responsibility for network regulation to the Australian Energy Regulator.

C.4 Procuring capacity

PWC is currently responsible for procuring capacity to meet customer demand not otherwise supplied by independent parties.

No specific generation reliability standard is promulgated.

The Utilities Commission Annual Reviews have reported on the status quo and forecast requirements against n-X and LoLP measures of generation reliability and found that current capacity is satisfactory under each measure until around 2020.²⁶

C.5 Daily operation

C.5.1 General Description of System Operation

The Power System Controller within PWC is responsible of operation of the power system in accordance with SCTC.

Current spinning reserve policy requires 25 MW spinning reserve in the Darwin-Katherine System.

The spinning reserve is typically dedicated to at least two generating units.

Generally dispatch instructions are implemented via an Automatic Generation Control (AGC) system.

PWC Generation determines its operating philosophy and unit commitment on a day-ahead basis and advises System Control and PWC Gas its requirements.

²⁶ Utilities Commission, Power System Review 2011-12, April 2013. Available at http://www.utilicom.nt.gov.au/PMS/Publications/09042013%202011-12%20Power%20System%20Review%20MASTER_%20FINAL.pdf

System Control liaises as needed with PWC Network to identify any constraints in the network and will operate ancillary services as required on a localised basis.

Analysis of the generation data in the Darwin-Katherine System indicates the forecast day ahead loads are reasonably predictable.

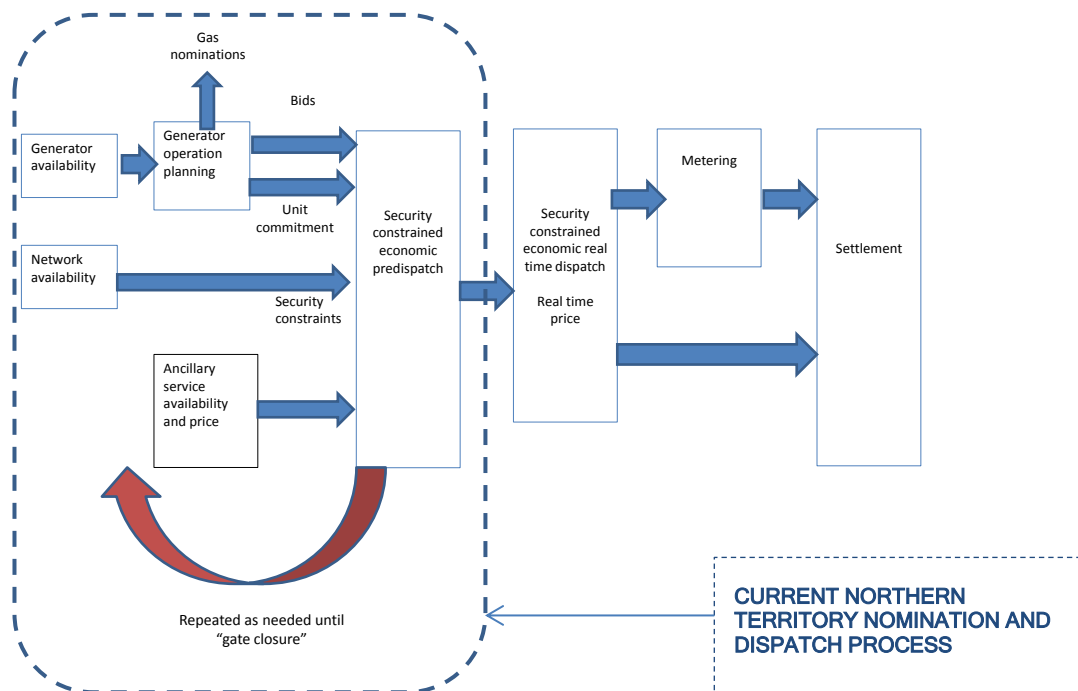
PWC Gas will dispatch gas supply (and transport to) the respective generators and advise its gas supplier (ENI) the total required gas on a day-ahead basis.

The following table summarises the process leading to energy dispatch and responsible party.

Table 2: Summary of responsible nominating parties

Process/Nomination	Responsible Party	Receiving Party
Day ahead forecast generation nominations	PWC Generation	System Control and PWC Gas
Generator availability	PWC Generation	System Control
Gas requirements at generators	PWC Generation	PWC Gas
Gas requirements at field	PWC Gas	ENI (gas supplier) on a bulk basis and gas transport operator
Network availability	PWC Network	System Control and PWC Generation
System constraints	PWC Network	System Control and PWC Generation
Dispatch	System Control	Power Stations / AGC

Figure 3: Energy Market Process showing current Northern Territory process



C.5.2 Out of balance transactions

The SCTC includes provision for independent generator-customer pairs to wheel energy through the PWC network. The SCTC requires these parties to self-balance and also provides for sell and buy bids for out of balance energy arising from wheeling. Under the SCTC the price for out of balance energy is set at the highest or lowest of the sell and buy prices accepted as appropriate.

No independent generation has operated in this way for a number of years.

Appendix D Applicability of NER energy market provisions (Chpt 3 and 4)

A review of the potential for the NER to be used as a template for the NTEM has been undertaken as part of this review. The following tables present an indicative assessment of the nature of amendments that would be required to adapt the NER to the NTEM in relation to the real time trading. Detailed instruction will be needed and the next steps will be influenced by where the rules making role is allocated.

A high level review of other provisions of the NER has also been undertaken and provided to the Utilities Commission. This part of review of the NEM has not been reported here as the changes cover many chapters and it is therefore a lengthy list and many are essentially consequential changes: for example references to inter regional settlements and network planning, operation and registration as well as to remove or de-activate provisions relating to market ancillary services and market network service providers. Although amendments would be required to many clauses the changes are conceptually relatively straightforward. We would expect consultation on specific proposals in due course.

Table 3 Energy market operations - indicative review of NEM rules as a template for NTEM

	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
Main clauses	<p>Chapter 3: Market Rules</p> <p>3.1 - Introduction to Market Rules</p> <p>3.1.4: Market design principles</p> <p>3.2: AEMO's Market Responsibilities</p> <p>3.2.2: Spot market</p> <p>3.4: Spot Market</p> <p>3.4.1: Establishment of spot market</p> <p>3.4.2: Trading day and trading interval</p> <p>3.4.3: Spot market operations timetable</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.1: Central Dispatch</p> <p>3.8.2: Participation in central dispatch</p> <p>3.8.5: Submission timing</p> <p>3.8.6: Generating unit offers for dispatch</p> <p>3.8.7: Bids for scheduled load</p>	<p>Chapter 4: Power System Security</p>	<p>Chapter 3: Market Rules</p> <p>3.7: Projected Assessment of System Adequacy</p> <p>3.7.1: Administration of PASA</p> <p>3.7.2: Medium term PASA</p> <p>3.7.3: Short term PASA</p>	<p>Chapter 3: Market Rules</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.20 - Pre-dispatch schedule</p>	<p>Chapter 3: Market Rules</p> <p>3.2: AEMO's Market Responsibilities</p> <p>3.2.4: Non-market ancillary services function</p> <p>3.11: Ancillary services</p> <p>3.11.1: Introduction</p> <p>3.11.3: Acquisition of Network Support and Control Ancillary Services</p> <p>3.11.4: Guidelines and objectives for acquisition of network support and control ancillary services</p> <p>3.11.4A: Guidelines and objectives for acquisition of system restart ancillary services</p> <p>3.11.4B: Determination of electrical sub-network boundaries</p> <p>3.11.5: Tender process for non-market ancillary services</p> <p>3.11.6: Dispatch of non-market ancillary services by AEMO</p>



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
					3.11.7: Performance and testing
Main clauses (cont')	3.8.8: Validation of dispatch bids and offers 3.8.9: Default offers and bids 3.8.21: On-line dispatch process 3.8.22: Rebidding 3.8.23: Failure to conform to dispatch instructions 3.9: Price Determination 3.9.1: Principles applicable to spot price determination 3.9.2: Determination of spot prices 3.9.4: Market Price Cap 3.9.5: Application of the Market Price Cap 3.9.6: Market Floor Price 3.9.6A: Application of the Market Floor Price 3.13: Market Information 3.13.4: Spot market				
Other relevant clauses	Chapter 3: Market Rules 3.1: Introduction to Market	Chapter 3: Market Rules 3.2: AEMO's Market	Chapter 3: Market Rules 3.2: AEMO's Market	Chapter 3: Market Rules 3.2: AEMO's Market	Chapter 3: Market Rules 3.8: Central Dispatch and Spot



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
	<p>Rules</p> <p>3.1.1: Introduction to Market Rules: Purpose</p> <p>3.6: Network Losses and Constraints</p> <p>3.6.2: Intra-regional losses</p> <p>3.6.4: Network constraints</p> <p>3.7: Projected Assessment of System Adequacy</p> <p>3.7.2: Medium term PASA</p> <p>3.7.3: Short term PASA</p> <p>3.7B: Unconstrained intermittent generation forecast</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.3: Bid and offer aggregation guidelines</p> <p>3.8.3A: Ramp rates</p> <p>3.8.4: Notification of scheduled capacity</p> <p>3.8.16: Equal priced dispatch bids and dispatch offers</p> <p>3.8.17: Self-commitment</p> <p>3.8.18: Self-decommitment</p>	<p>Responsibilities</p> <p>3.2.3: Power system operations</p> <p>3.7: Projected Assessment of System Adequacy</p> <p>3.7.1: Administration of PASA</p> <p>3.7.2: Medium term PASA</p> <p>3.7.3: Short term PASA</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.1: Central dispatch</p> <p>3.8.2: Participation in central dispatch</p> <p>3.8.3: Bid and offer aggregation guidelines</p> <p>3.8.10: Network constraints</p> <p>3.8.11: Ancillary services constraints</p> <p>3.8.20 - Pre-dispatch schedule</p> <p>3.11: Ancillary services</p> <p>3.11.1: Introduction</p> <p>3.11.3: Acquisition of Network Support and Control Ancillary Services</p> <p>3.11.6: Dispatch of non-market</p>	<p>Responsibilities</p> <p>3.2.3: Power system operations</p> <p>3.7: Projected Assessment of System Adequacy</p> <p>3.7B: Unconstrained intermittent generation forecast</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.3: Bid and offer aggregation guidelines</p> <p>3.8.9: Default offers and bids</p> <p>3.8.17: Self-commitment</p> <p>3.8.18: Self-decommitment</p> <p>3.8.19: Dispatch inflexibilities</p> <p>3.13: Market Information</p> <p>3.13.4: Spot market</p> <p>Chapter 4: Power System Security</p> <p>4.3: Power System Security Responsibilities and Obligations</p> <p>4.3.1: Responsibility of AEMO for power system security</p> <p>4.9: Power System Security Related Market Operations</p>	<p>Responsibilities</p> <p>3.2.2: Spot market</p> <p>3.7: Projected Assessment of System Adequacy</p> <p>3.7.3: Short term PASA</p> <p>3.7B - Unconstrained intermittent generation forecast</p> <p>3.8: Central Dispatch and Spot Market Operation</p> <p>3.8.9: Default offers and bids</p> <p>3.8.17: Self-commitment</p> <p>3.8.18: Self-decommitment</p> <p>3.13: Market Information</p> <p>3.13.4: Spot market</p> <p>4.9: Power System Security Related Market Operations</p> <p>4.9.1: Load forecasting</p>	<p>Market Operation</p> <p>3.8.1: Central dispatch</p> <p>3.8.3: Bid and offer aggregation guidelines</p> <p>3.8.11: Ancillary service constraints</p> <p>3.8.13: Notification of constraints</p> <p>3.8.20: Pre-dispatch schedule</p> <p>Chapter 4: Power System Security</p> <p>4.1: Introduction</p> <p>4.1.1: Purpose</p> <p>4.2: Definitions and Principles</p> <p>4.2.6: General principles for maintaining power system security</p> <p>4.3: Power System Security Responsibilities and Obligations</p> <p>4.3.1: Responsibility of AEMO for power system security</p> <p>4.3.4: Network Service Providers</p> <p>4.3.5: Market Customer obligations</p>



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
	3.8.19: Dispatch inflexibilities	ancillary services by AEMO	4.9.1: Load forecasting		
Other clauses (cont')	3.8.20: Pre-dispatch schedule 3.8.22A: Variation of offer, bid or rebid 3.9: Price Determination 3.9.3A: Reliability standard and reliability settings review 3.9.3B: Reliability standard and reliability settings review report 3.9.7: Pricing for constrained-on scheduled generating units 3.13: Market Information 3.13.1: Provision of information 3.13.3: Standing data 3.13.8: Public information	3.20: Reliability and Emergency Reserve Trader 3.20.2: Reliability and emergency reserve trader 3.20.3: Reserve contracts 3.20.7: AEMO's exercise of the RERT 3.20.8: RERT guidelines			4.5: Control of Power System Voltage 4.5.1: Power system voltage control 4.8: Power System Security Operations 4.8.4: Declaration of conditions 4.8.12: System restart plan and local black system procedures 4.9: Power System Security Related Market Operations 4.9.2: Instructions to Scheduled Generators and Semi-Scheduled Generators 4.9.3A: Ancillary services instruction 4.9.5: Form of dispatch instructions 4.9.8: General responsibilities of Registered Participants 4.10: Power System Operating Procedures 4.10.2: Transmission network operations



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
					4.11: Power System Security Support 4.11.1: Remote control and monitoring devices
Rule objective	<p>Dispatch is premised on optimal²⁷ use of scheduled resources subject to:</p> <ul style="list-style-type: none"> ▪ bids / offers ▪ network / security constraints. <p>Assumption that offered / bid price represents the marginal cost of supply.</p> <p>There are consequences for failure to act in accordance with dispatch instructions.</p>	<ul style="list-style-type: none"> ▪ To ensure that at all times the power system is operated within its technical envelope ▪ To ensure there are services and systems in place to (in a timely manner) respond to, and manage, both credible and non-credible contingency events 	<p>Defines basic structure for identifying potential lack of reserve</p> <ul style="list-style-type: none"> ▪ MT PASA: nature of inputs; daily resolution for peak demand (x% probability of exceedence); 24 months ahead; updated weekly. ▪ ST PASA: nature of inputs; half-hourly resolution for peak demand (x% probability of exceedence); 6 days after end of pre-dispatch; updated daily 	<p>The primary purpose of pre-dispatch is to:</p> <ul style="list-style-type: none"> ▪ provide wholesale market participants with sufficient unit loading, unit ancillary service reserve and regional pricing information for them to make informed and timely business decisions relating to the operation of their dispatchable units. ▪ provide the wholesale market operator (AEMO) with sufficient information to assist them in maintaining the power system in a reliable and secure operating state in accordance with the Rules obligation. 	<p>Ancillary services are to be available for dispatch by the system operator in order to adequately manage:</p> <ul style="list-style-type: none"> ▪ moment-to-moment variation in system conditions; ▪ credible contingency events; and ▪ recovery from non-credible contingency events.

²⁷ In the absence of scheduled/dispatchable load, this would translate to least cost dispatch of generation.



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
				<p>Pre-dispatch delivers a look ahead for <u>trading interval</u> prices up to two days ahead based on:</p> <ul style="list-style-type: none"> ▪ bids and offers currently submitted; and ▪ fixed sensitivities to variations between (possible) actual system load and current forecast system load 	
Notes	<p>Identification of key clauses focusses on dispatch and pricing for energy.</p> <p>Key words:</p> <ul style="list-style-type: none"> ▪ price / pricing ▪ dispatch ▪ trading interval ▪ spot market <p>Excludes consideration of</p> <ul style="list-style-type: none"> ▪ reserve / RERT management ▪ settlement processes ▪ prudential matters ▪ intervention / directions ▪ administered pricing / 				



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
	<p>market suspension</p> <ul style="list-style-type: none"> management of errors / incorrect inputs. 				
Rule changes	<p>Need to define length of trading / dispatch interval.</p> <p>A price cap and price floor need to be determined as well as the period over which it will be reviewed.</p> <p>Delete references to, and all clauses that rely on “ancillary services prices”.</p>	<p>Delete references to, and all clauses that rely on:</p> <ul style="list-style-type: none"> “Scheduled Network Service Providers” “market ancillary services”. <p>Need to manage / combine clauses that separately deal with TNSPs and DNSPs.</p> <p>Possibly delete 4.16 and 4.17.</p>	<p>Minor changes only required: references to:</p> <ul style="list-style-type: none"> “AEMO” “each region” “NSPs” (plural) probability of exceedence: consider whether 10% probability of exceedence is appropriate. <p>Delete references to, and all clauses that rely on:</p> <ul style="list-style-type: none"> “interconnectors” “market network services”. 	<p>Minor changes only required: references to:</p> <ul style="list-style-type: none"> “AEMO” “each region”. <p>Delete references to, and all clauses that rely on:</p> <ul style="list-style-type: none"> “Scheduled Network Service Providers” “market ancillary services”. 	<p>Comprehensive re-write required.</p> <p>Delete references to, and all clauses that rely on:</p> <ul style="list-style-type: none"> “market ancillary services” “ancillary services prices” “ancillary services settlement” “value of ancillary services”. <p>Network support and control ancillary services (voltage control and network loading control) to be contracted similarly to those services in the NEM.</p> <p>System restart services to be contracted.</p> <p>Frequency control (or load following) services to be contracted.</p> <p>Consideration to be given to the desirability of clause to enforce contracting on “reasonable”</p>



	Dispatch & pricing	Power system security	Projected assessment of system adequacy (PASA)	Pre-dispatch	Ancillary services
					terms where tenders are non-competitive.
Procedure requirements	The detail of the dispatch and pricing algorithm will be specified in procedures.		Detailed information gathering, calculation and publication procedures need to be developed.	The detail of pre-dispatch operation and design is covered in procedures. The Rules merely provide the basic framework for pre-dispatch as it applies to trading intervals. AEMO also operates a shorter term <u>dispatch interval based</u> pre-dispatch process that is not required by the Rules but is nevertheless supported by participants as a valuable short-term planning tool.	