RULE

Australian Energy Market Commission

CONSULTATION PAPER

NATIONAL ELECTRICITY AMENDMENT (SHORT TERM FORWARD MARKET) RULE 2019

PROPONENT

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INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

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1 INTRODUCTION

On 20 December 2018, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) seeking to introduce a market for trading short term forward contracts for electricity in the national electricity market (NEM). The proponent suggested the proposed short term forward market (STFM) could improve short term spot price risk management for a range of participants including intermittent renewable generators, gas fired generators, wholesale consumers and demand response participants.

This consultation paper has been prepared to facilitate public consultation on the rule change request and to seek stakeholder submissions.

This paper:

- sets out a summary of, and a background to, the rule change request
- identifies a number of questions and issues to facilitate the consultation on this rule change request
- outlines the process for making submissions.

2 BACKGROUND

This section provides an overview of:

- existing risk management options used by national electricity market (NEM) participants currently
- ahead markets implemented outside the NEM, that follow a similar structure to the proposed STFM
- the AEMC's 2018 Reliability frameworks review, which recommended a short term forward market be assessed in a rule change process.

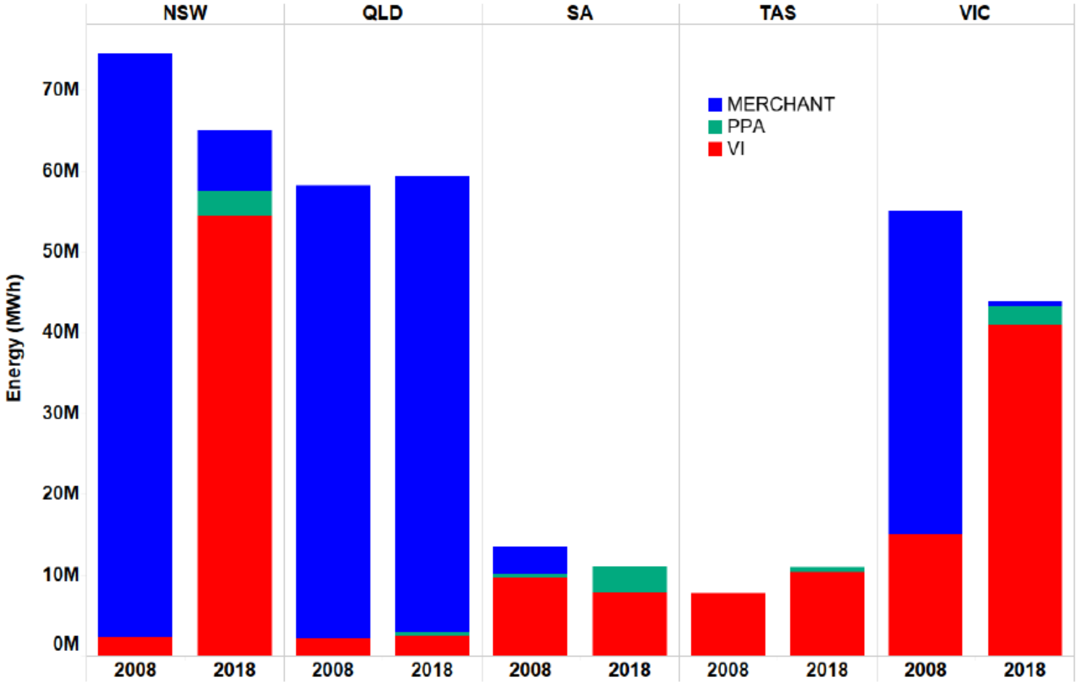
2.1 Current risk management options

The NEM operates as a gross pool market, where generators bid in different quantities of generation at different prices. AEMO then clears the market by balancing supply and demand every five minutes at the price of the marginal generator. As demand and supply vary continuously throughout the day, so does the electricity price. The fluctuations between the market floor price (-$1,000/MWh) and the market price cap ($14,500/MWh) create risk for wholesale and retail participants. For instance, if there was an extended extreme weather event resulting in a significant increase in demand, and a resulting increase in the wholesale price of electricity, a retailer may suffer financial stress. Alternatively, if there was a period of low, stable prices, a peaking generator may find itself under financial pressure as it would be unable to recover its fixed costs. The market has responded to managing these risks through:

- vertical integration
- financial hedging contracts
- other risk management products.

Vertical integration involves investment in both the generation and the retail ends of the market. This commercial structure allows the participant to balance the negative cash flow risk on the generation side (low wholesale electricity prices) with the negative cash flow risk on the retail side (high wholesale electricity prices). While this can be an effective method of risk management, this option is a long-term strategy that requires significant capital reserves to invest in physical generation. Over the past 10 years, vertical integration has become an increasingly popular form of risk management in Victoria and New South Wales, as illustrated by the change in output ownership across the NEM in Figure 2.1.

Figure 2.1: Output ownership over time



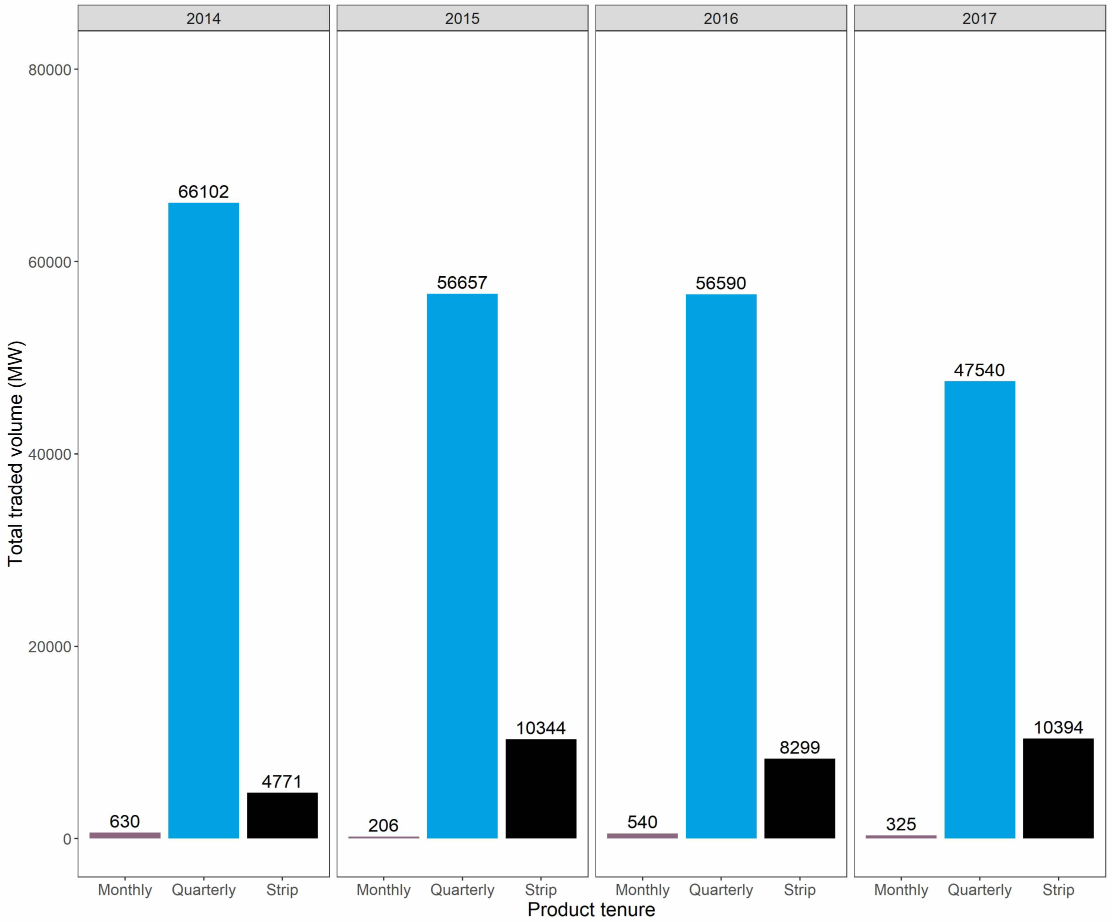
Source: AEMC analysis
Note: The above graph makes a simplifying assumption that generation owned by a business with a retail arm is 'vertically integrated'. We have not made adjustments to reflect situations where such a vertically integrated entity may be net long or net short of generation.

Financial hedging contracts are a common way for participants to hedge against spot price risk. Financial hedges allow counterparties to agree today to a fixed price for a financial transaction in the future based on the price of an underlying asset or commodity, such as the NEM spot price. As the value of the financial product is *derived* from the value of the underlying asset, these products are called 'derivatives'.[1] There are broadly two markets for financial derivatives: The Australian Securities Exchange (ASX) and the bi-lateral or over-the-counter (OTC) contracts market.

Contracts traded on the ASX are standardised, and anonymous. Traded volumes and prices are listed on the exchange, providing valuable information to the market about the current value of different products. The ASX offers a range of products, such as swaps and options, for a range of tenures including annual (strips), quarterly, and monthly. Figure 2.2 illustrates the trades of electricity products currently listed on the ASX by tenure. Historically, quarterly products have been the most common tenure traded, and monthly products are the least traded.

1 For the purposes of regulation of financial products, derivative is defined under Chapter 7 of the Corporations Act 2001 (Cth) — See section 761D(1) of the Act.

Figure 2.2: ASX traded electricity futures by product tenure

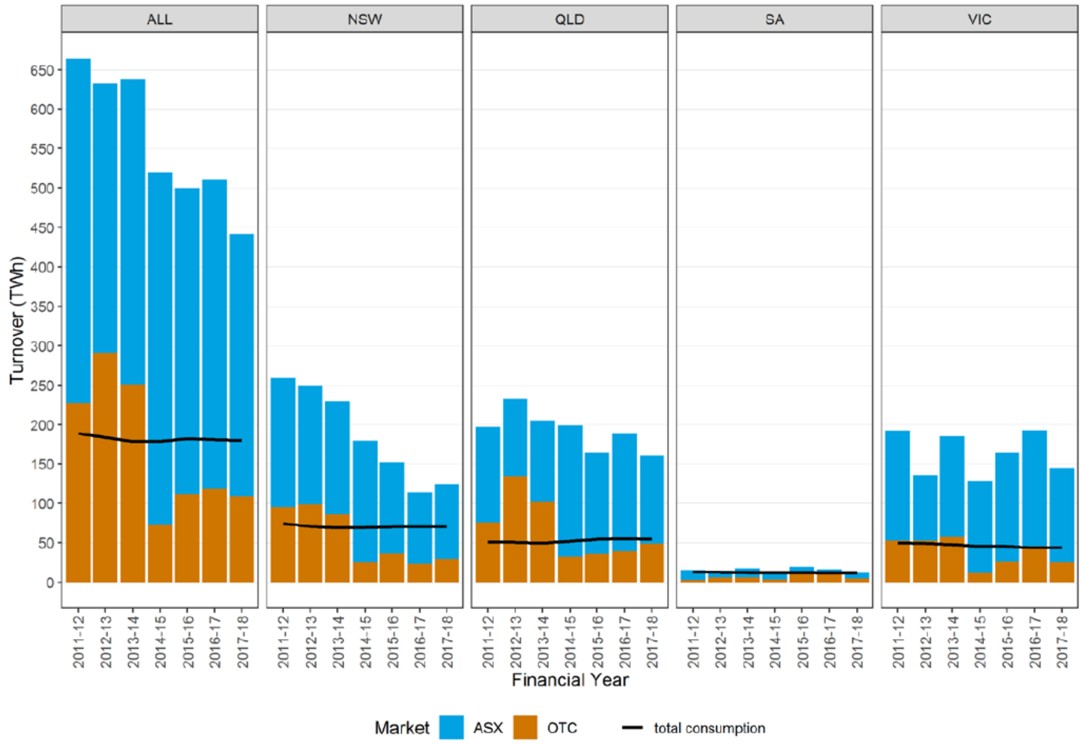


Source: AEMC analysis of ASX Energy data
Note: Data includes all product types, such as swaps and options across all regions.

OTC contracts are bi-lateral agreements between generators and retailers/market customers. While OTC contracts can have a similar structure to ASX contracts, they are negotiated directly by the two counterparties, and can include bespoke positions. There is less publicly available information on OTC contracts, however the Australian Financial Markets Association (AFMA) conduct an annual survey of participants which reports the volumes of OTC contracts traded in each region. Figure 2.3 below illustrates the turnover of both ASX and OTC electricity contracts over time. Generally, ASX electricity products trade higher volume than OTC products, however these proportions change from year to year.[2]

2 For example, during 2015-17 in South Australia there was higher trade in OTC contracts than ASX contracts.

Figure 2.3: ASX and OTC turnover for electricity derivatives



Source: AEMC analysis of AFMA 2018 survey data

Power purchase agreements (PPAs) are a common type of OTC contract used by renewable generators. PPAs are an off-take agreement, between a generator and another party (usually a retailer or market customer), where the retailer/consumer agrees to purchase some or all the electricity exported to the grid by the generator, regardless of when and how much is generated, for a fixed dollar amount per megawatt hour. These agreements are very popular with wind farms and solar plants where the plant has little control over when electricity is generated. This intermittency in generation results in PPAs trading at discounted prices to swap or option contracts.

Other risk management products, such as weather derivatives or proxy revenue swaps, are offered by parties outside of the energy industry such as insurance companies. Weather derivatives hedge against the risk of specific weather characteristics such as temperature, precipitation, and wind, which can impact the ability to generate electricity or its price. For example, this could be used by a wind generator to hedge against the negative cash flow risk of calm days, or by a retailer to hedge the demand peak on exceptionally hot days.

Proxy revenue swaps (PRS) are relatively new to the energy industry, and have been used by several renewable generators in the past few years. PRSs have also been offered by some insurance/reinsurance companies and overseas they have been offered by financial institutions. A PRS essentially involves a generator receiving a fixed lump-sum amount per quarter, regardless of the amount of electricity generated or the price the electricity is cleared at through the market. In return, the generator passes all revenue through to the counterparty. These products are similar to a contract-for-difference, however they hedge against volume risk, in addition to price risk.[3]

2.2 Short term ahead markets

A short term ahead market is a feature of many spot markets, most often implemented as a day ahead settlement. This makes the real time market a balancing market for difference between day ahead and actual quantities of generation and demand. There are broadly two categories of short term ahead markets:

- American-style ahead markets
- European-style ahead markets.

The following sections explore how these types of markets operate and provide examples of where they currently operate today. While there are a number of short term ahead markets operating in international electricity markets, the design of the NEM is relatively unique and varies from other markets with existing ahead markets. In assessing the design elements of different schemes, it is therefore important to consider how the elements operate within an overall system design.

2.2.1 American-style ahead markets

American-style ahead markets facilitate mandatory participant-to-system operator actions for the system operator to schedule efficient and reliable operations. These markets generally involve mandatory, and financially binding commitments of generation to the market operator ahead of the trading day. It has the following objectives:

- To provide generation and pricing information to the system operator in the form of financially binding operating schedules and physical resource operating parameters for the day. This allows the system operator to schedule plant to meet expected demand of the system the following day and evaluate operational conditions on high stress days.
- To provide market participants with financially binding schedules to support physical unit commitments including fuel scheduling.
- To provide information to system operators to schedule cross-border flows between different regional markets for the following day (which is not a relevant consideration in the NEM)

Some markets that currently operate an American-style ahead market include California, New York, the PJM market and the Electric Reliability Council of Texas (ERCOT). Additionally, the wholesale electricity market in Western Australia (WA) also operates a day ahead market. Box 1 below provides an overview of the WA market that operates on the South-West Interconnected System (SWIS).

3 For more information see: https://projectfinance.law/publications/2018/june/proxy-revenue-swaps-for-solar

BOX 1: THE WHOLESALE ELECTRICITY MARKET IN WESTERN AUSTRALIA

The wholesale electricity market (WEM) in WA has a different market design to the NEM. The main features of this market are:

- **Reserve capacity mechanism**: the primary role of the reserve capacity mechanism is to ensure that there is adequate generation and demand side management capacity available each year to meet peak system requirements including a reserve margin. Each market customer is required to contract for 'capacity credits' to cover their share of capacity procured to cover the total system requirement. The market operator (AEMO) assigns capacity credits to suppliers of registered capacity. If there are insufficient capacity credits to meet requirements, AEMO will run an auction to procure more capacity to cover the remaining requirements of market customers.
- **Bilateral contracts**: bilateral trades of energy and capacity occur between market participants. However, market participants are required to submit bilateral schedule data pertaining to bilateral energy transactions to AEMO each day so that the transactions can be scheduled.
- **Short-term energy market (STEM)**: the STEM is a daily forward market for energy that allows market participants to trade around their bilateral energy position, producing a net contract position. A STEM auction is run for each trading interval of the next trading day, determining a STEM clearing price and clearing quantities. The combined net bilateral position and STEM position of a market participant describes its net contract position.
- **Dispatch and balancing process**: the balancing process involves AEMO determining actual generation requirements and a balancing price for each trading interval. Generators receive or pay the balancing price for any quantity above or below their net contract position respectively. Similarly, market customers pay or receive the balancing price for any quantity above or below their net contract position.

There are a number of differences between this market design and the NEM. First, the WEM includes a capacity mechanism. Generators receiving capacity credits in the capacity market must offer all of their available capacity for which they have received credits into the STEM and balancing market, preventing the physical withholding of capacity. Second, the WEM rules require suppliers to provide energy at their reasonable expectation of short-run marginal cost. This and the ex-post monitoring and investigation of bidding behaviour seek to mitigate the misuse of market power in the WEM. This is necessary because of the lack of effective competition in the wholesale energy market.

Source: AEMC 2018 Reliability Frameworks Review, Final report, pp. 223-224.

2.2.2 European-style ahead markets

A European-style ahead market facilitates participant-to-participant trades of contracts ahead of real-time. These contract markets are typically voluntary trading exchanges where participants trade simple price-quantity bids to meet the following objectives:

- To concentrate trading liquidity at a certain point in time. This is because trading is defined around a specific period, e.g. the day-ahead. In contrast, contract trading in the NEM is continuous and is not forced to occur a specific period ahead of time. This potential for greater liquidity may provide greater confidence to market participants that the price signals observed properly reflect the underlying demand-supply balance. In turn, because there may be greater confidence in prices observed in the market, this might provide better investment and operational signals to participants.
- To allow market participants to fine-tune previous traded positions ahead of real time and/or to hedge against volatility in the real time market.
- To provide information to the market ahead of the real time market as to the likely scarcity of generation relative to expected demand over the coming 24-hour period. In turn, this may influence individual plant operating decisions.

In essence, this European-style, participant-to-participant market is a 'trading tool' that provides price signals and a risk management facility to market participants.

Some markets that currently operate European-style ahead markets include the United Kingdom, France and Germany, which all operate on a day-ahead basis.

2.3 Reliability frameworks review

In 2018, the AEMC released the final report of its Reliability Framework Review (RFR). To address a recommendation from the Independent Review into the Future Security of the National Electricity Market (the Finkel review), the RFR assessed "the suitability of a 'day-ahead' market to assist in maintaining system reliability".[4] The assessment of ahead markets explored the suitability of both American-style, and European-style ahead markets, and gathered a range of stakeholders submissions on the possible options.

In the RFR, the Commission noted it did not consider an American-style ahead market (that would transfer unit commitment decisions from market participants to the system operator) as suitable for the NEM to manage reliability outcomes, as it would impose large costs on the market with limited benefit.[5] Further, an American-style ahead market may not necessarily improve system security outcomes or reduce the cost of interventions. With or without an ahead-market, the potential benefits can only accrue if an explicit value is placed on the required system security services.

The Commission suggested a European-style shorter-term trading market may be beneficial as it is similar to current market arrangements, with limited barriers to the introduction of such a market in the NEM. These benefits include providing market participants with more

4 Finkel Panel, Independent Review into the Future Security of the National Electricity Market:Blueprint for the Future, June 2017, p. 23.

5 AEMC, Reliability Frameworks Review, Final Report, 26 July 2018, p. 2.

options to manage price risk and to provide more price certainty to market participants. A benefit of increased price certainty is that it may facilitate more demand response in the wholesale market. As a result, the Commission recommended that AEMO undertake work to submit a rule change request to the Commission on how a short-term forward market could be developed that would facilitate bi-lateral trading of financial contracts closer to real time, with the aim of providing the demand side with more opportunities to lock in price certainty.

3 DETAILS OF THE RULE CHANGE REQUEST

This section outlines the proponent's views put forward in the rule change request:

- statement of issues
- proposed solution
- potential costs and benefits of implementing the proposed solution.

The rule change request does not include a proposed rule. A copy of the rule change request may be found on the AEMC website, www.aemc.gov.au/rule-changes/short-term-forward-market.

3.1 Statement of issues

AEMO described the market context for the rule changes as having

- high levels of intermittent generation and growing demand for flexible generation
- potential barriers to demand side participation and significant creditworthiness and collateral requirements for smaller participants.

It suggests a range of participants could potentially benefit from the introduction of a STFM as it could provide:

- another risk management option for intermittent generators closer to the trading day when these generators have greater certainty of what they will be generating
- greater short term price visibility and certainty for gas-powered generators to better coordinate between generating electricity and selling gas into gas markets
- more price visibility and risk management options available for end users, and those able to offer wholesale demand response
- lower barriers to market participation from clearing systems and settlement that isn't fully integrated with existing risk management tools
- stronger investment signals for investors.[6]

3.2 Proposed solution

The rule change request proposes that a short term forward market (STFM) be established to operate alongside the NEM and the existing contracts market. The market could follow a similar model to that used in the Gas Supply Hubs (GSH),[7] using the same platform and processes for clearing, settlement and prudential arrangements. The specific characteristics of the proposed market include:

- being operated by AEMO using the existing Trayport platform used for the GSH and pipeline Capacity Trading Platform (CTP)[8]
- using NEM settlement, clearing and prudential frameworks where practicable

6 AEMO, Short term forward market rule change proposal, p. 3.

7 See appendix a.1 for more information.

8 See appendix a.2 for more information.

- voluntary participation by market participants
- anonymous, exchange trading of standardised short term electricity contracts with bids and offers matched continuously based on price and linked to each regional reference price in $/MWh
- contracts traded daily on a rolling basis for the following day and up to seven days in advance (D+1 to D+8)
- contract specifications developed with industry with the potential for contracts over daily, hourly, peak or shoulder block contract durations
- transaction prices and quantities published on the AEMO website.[9]

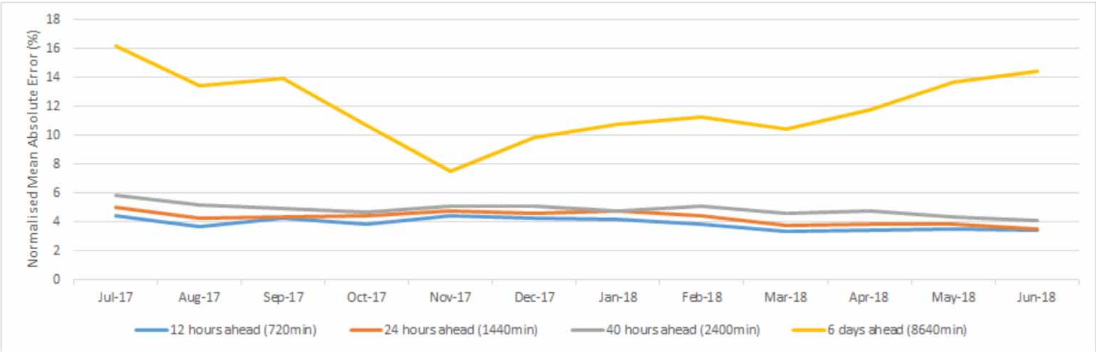
3.3 Potential benefits

The rule change proponent suggests the introduction of the STFM is expected to give participants more options to manage price risk and hedge their positions ahead of the trading day. Specifically, the proponent identified three categories of participants which the STFM may directly benefit, namely, wind and other intermittent generators, gas powered generators and demand side response participants. There may also be benefits to integrating the STFM with NEM settlement and prudentials.

3.3.1 Intermittent renewable generators

As noted in section 2.1, intermittent renewable generators have historically been mostly underwritten by PPAs. Some of these generators that are not on PPAs have limited options to manage their risk in the short term. Wind generators, for instance forecast their output relatively accurately on a short term basis, as illustrated in Figure 3.1 below.

Figure 3.1: Australian wind forecast accuracy



Source: AEMO, Short term forward market rule change proposal, p. 9.

The introduction of a STFM could encourage such intermittent generators to sell short-term products swap or option products, if they are confident they will be able to generate and defend them. Alternatively, this could enable an intermittent generator to sell a longer term

9 AEMO, Short term forward market rule change proposal, p. 4.

swap product, and if they are aware that they are unable to defend the product, they could purchase some short-term firming products from the STFM.

3.3.2 Gas powered generators

Through the introduction of a STFM, gas powered generators could gain additional certainty from short term pricing, allowing them to better coordinate decisions between gas and electricity supply. Gas powered generators could also lock-in electricity market revenue, to underwrite the purchase of both physical gas from one of the gas markets and the purchase of pipeline capacity. The proponent provides the following example:

"For example, a GPG could purchase a weekly gas contract on the GSH and then sell short term contracts on a STFM seven days out. In this way, a GPG could potentially use the STFM to offer additional contracts above its OTC/ASX/vertically integrated position if it had the spare capacity and the ability to take advantage of short term gas."[10]

3.3.3 Demand response participants

Some large electricity users in the NEM have the ability to adjust their processes and reduce their demand in response to high price events. These large users can also enter into forward contracts to manage spot price risk exposure. If large users directly participate in the NEM and retain spot exposure they can obtain a financial benefit by reducing load to avoid spikes in spot prices. However through the introduction of a STFM, large users that are fully hedged and capable of providing demand response, could on-sell some of their hedging products in the short term. Box 2 below provides a worked example of how demand response could operate on a STFM.

BOX 2: DEMAND RESPONSE STFM EXAMPLE

An energy customer is participating in the STFM and the wholesale spot electricity market.

The customer is able to change their level of consumption. However, the customer will incur costs of $5,000 to undertake demand response and given factory operational constraints, they have to commit to this demand response some days ahead of the trading day.

In addition, the customer will now have some unhedged load in the short term.

They decide to hedge some previously unhedged load in the short term forward market: the customer buys 100 MWh for the next day in the short term forward market at a price of $50/MWh.

The next day, an unexpected contingency occurs and the wholesale price for electricity rises to $500/MWh for the relevant period. The customer decides not to consume the additional 100 MWh it hedged on the STFM and is paid the difference between the short-term forward market price and the spot price.

10 AEMO, Short term forward market rule change proposal, p. 9.

Result

The customer's net outcome is:

- (100 MWh * ($500 - $50)/MWh) = $45,000
- the customer also incurs the cost of demand response: -$5,000
- the net position through use of a STFM for the customer is: $40,000

Source: AEMO, Short term forward market rule change proposal, p. 12.

3.3.4 Integrated settlements and prudentials

Finally, AEMO suggests that an integrated settlement and prudential framework between the STFM and the NEM spot market could lower transaction costs through:

- "a single invoice and net payment
- the ability to offset settlement exposures between the two markets
- potentially the ability to make a single security payment that covers both markets."[11]

3.4 Potential costs

In the rule change proposal, AEMO suggested it could run an STFM at relatively low cost, as many participants already use Trayport and are set up with NEM prudential and settlement systems.[12]

However, the rule change proposal does identify the potential costs for both AEMO and participants associated with Australian Financial Services Licence (AFSL) requirements, which may apply depending on the eventual design of any STFM. The market design and approach to licensing (including whether AEMO or participants are able to obtain exemptions from AFSL requirements) will impact on the cost of implementing the market and, ultimately, the liquidity of that market. AEMO goes on to note that it is "important that legal and regulatory certainty is achieved for the chosen path".[13]

11 AEMO, Short term forward market rule change proposal, p. 11.
12 AEMO, Short term forward market rule change proposal, p. 14.
13 AEMO, short term forward market proposal, p. 5.

4 ASSESSMENT FRAMEWORK

4.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[14] This is the decision making framework that the Commission must apply.

The NEO is:[15]

> To promote efficient investment in, and efficient operation and use of, electricity services for the longer term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

4.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

4.3 Making a differential rule

Under the Northern Territory legislation adopting the NEL, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

As the proposed rule change is unlikely to relate to parts of the NER that currently apply in the Northern Territory, it is unlikely the Commission will have to assess any changes to the NER against additional elements required by the Northern Territory legislation.[16]

14 Section 88 of the NEL.

15 Section 7 of the NEL.

16 From 1 July 2016, the NER, as amended from time to time, apply in the NT, subject to derogations set out in regulations made under the NT legislation adopting the NEL. Under those regulations, only certain parts of the NER have been adopted in the NT. (See the AEMC website for the NER that applies in the NT.) National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

4.4 Proposed assessment framework

At this stage, the Commission is seeking stakeholder views on its proposed assessment framework which includes the following criteria:

- **Effective risk allocation and management:** would the mechanism enable market participants to improve their risk management (i.e. better manage price and volume risk)?
- **Efficient investment in, and operation of, energy resources:** would the mechanism promote signals for efficient investment in generation and demand response infrastructure? Would it improve the efficiency of operation of the NEM, leading to improved reliability?
- **Promoting competition in upstream and downstream markets:** would the mechanism promote competition among generators, retailers and end users or address factors that are a deterrent to large users participating in the market? Would the STFM improve wholesale market competition, retail competition, and outcomes for consumers including prices?

5 ISSUES FOR CONSULTATION

Taking into consideration the assessment framework, a number of issues have been identified for initial consultation. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper, including the proposed assessment framework.

This chapter outlines:

- the current risk management approaches used by participants
- design elements of a STFM
- implementation costs.

5.1 Current risk management

As identified in section 3.3, the proponent has identified several proposed benefits from the introduction of a STFM for different parties, in summary:

- Variable renewable energy (VRE) generators may firm and on-sell their generation
- gas powered generators may gain additional short-term price certainty
- energy users may hedge against short term price rises and sell demand response

For the STFM market to be effective, and warranted, the proposed benefits need to be able to be realised, material, and additional to existing risk management options.

5.1.1 Firming of VRE generation

As discussed in section 2.1, most VRE generators such as wind and solar generators sell their generation through PPAs, while noting that some of these generators are merchant and use risk management products such as weather derivatives or other firming products to manage their risk. As the long term PPAs of VRE generators expire, this presents the decision to either:

- move on to another PPA or financial instrument that fully hedges price and/or volume risk (e.g. PRS);
- become a merchant generator that actively manages price risk; or
- a combination of the two.

If a VRE generator opts to either partly or fully become a merchant generator, then the introduction of a STFM could expand the options for price risk management for these participants. This decision to become a merchant generator could potentially involve trading the surety of a PPA for the higher value but higher risk spot market. Additionally, it would significantly shift the current operating model for these plants, and may require these generators to hire traders to actively manage spot price risk.

QUESTION 1: CURRENT RISK MANAGEMENT FOR INTERMITTENT RENEWABLE GENERATORS

1a) How do VRE generators currently manage their spot price risk in the short term? Is there a preference for fully hedging around price and/or volume risk, or an actively managed risk model?

1b) Would a STFM assist VRE generators to manage their risk? If so, how (in particular given the expectation that short term contract prices will approach the spot price closer to the delivery period)? What benefits are there? What products should be listed?

5.1.2 Price certainty for gas powered generators

Gas powered generators that operate only during peak periods tend to use risk management tools, such as selling cap contracts and other types of options, to ensure they cover both their fixed and variable costs. In order to defend such a contract or simply generate to capture spot price spikes, the gas powered generator would need to keep a store of gas sufficient to generate the electricity required. The gas powered generator would also need to optimise the decision between generating electricity and selling that gas on the gas market (known as the spark spread). If the generator is better able to react to price signals, this should deliver better outcomes for the generator and consumers in both the electricity and gas markets.

The introduction of a short term forward market has the potential to enable gas fired generators to secure short term contracts for electricity generation, potentially assisting both end users that desire a greater level of coverage from anticipated price spikes and other generators that need to firm up their generation to defend hedging products they have already sold. This could be beneficial to both VRE generators, and any traditional generators that face unexpected outages on one of their units. For example, if there is an anticipated price spike a week ahead, the gas powered generator could:

- purchase a short term gas commodity product on the GSH
- purchase transportation rights on the CTP
- sell a short term product on the STFM.

One issue that could potentially affect the demand for short term products is the relationship of additional information on expected price. As the trading period is approached, more information becomes available to both sides of the market, this new information could drive demand for a short term product, however the party selling the product would only sell a short term product, if the expected value (the product of probability and payoff), exceeded the expected value of selling electricity directly onto the spot market.

For example, if very high temperatures were forecast for in a few days' time and an industrial user was not fully hedged and wanted to purchase a short term contract, the counterparty to the contract (e.g. a gas powered generator) would only agree to sell the user a contract in the short term forward market if the expected value of the contract, exceeded the revenue the generator expected to make by selling the same quantity of electricity at spot prices. This is the usual trade-off for existing hedging products. However, more information becomes available to both parties and the potential for change reduces as the high temperature days get closer, which makes the difference between spot exposure and contract premium smaller.

QUESTION 2: CURRENT RISK MANAGEMENT FOR PEAKING GENERATION

2a) Would the introduction of a STFM improve the risk management capability of a gas powered generator? If so, how (in particular given the expectation that short term contract prices will approach the spot price closer to the delivery period)? Are there any OTC products that currently exist that serve a similar purpose? What kind of products would be beneficial to be listed?

2b) Would the introduction of a STFM assist in optimising spark spreads for gas powered generators?

2c) Are there any reasons the STFM would not be used by gas powered generators? Would the differential between expected value of selling a short term product and trading directly on the spot be sufficient to warrant the use of the short term product? How often and for what volume (proportion of a portfolio) would this assist?

5.1.3 End users hedging price spikes and offering demand response

As noted in section 2.1, market customers and retailers that trade on the wholesale market have traditionally hedged against spot market fluctuations through vertical integration, contracting using ASX and OTC products, and to a lesser extent through the use of other risk management products such as weather derivatives. While some OTC contracts may be traded that mature in just a few days, there are no exchange traded products that meet this need. The ASX could list a short term product, if they thought there was unmet demand for such a product, but have not done so to date. As noted in section 5.1.2, for a short term product to be valued by the market there needs to be sufficient difference between the listed price for the short term product and expected price of purchasing electricity on the spot market.

Another potential benefit of a STFM for both industrial users and retailers is the creation of a potential avenue for participants with demand response capabilities to access a value stream from the market. Currently, some retailers offer demand response products to commercial and industrial users such as ERM Power and Flow power, while other retailers have demand response products for their mass market customers such as Powershop and Ergon Energy.[17]

The establishment of a formal exchange through the STFM may provide greater options for users to provide demand response (DR). Some physical demand response participants need lead time to enact the demand response — the process of shutting down and restarting

17 For further details see: ERM Power — https://www.ermpower.com.au/wp-content/uploads/2017/11/Demand-Response.pdf; Flow Power — https://flowpower.com.au/turn-your-power-demand-into-income/; Powershop — https://www.powershop.com.au/demand-response-curb-your-power/; Ergon Energy — https://www.ergon.com.au/network/manage-your-energy/incentives/peaksmart-air-conditioning.

industrial processes is not instantaneous. It can therefore be difficult for DR participants to react to short run price spikes, particularly after the introduction of five minute settlement.[18] Having increased surety of a demand response contract can be beneficial for the DR participant. As described in section 3.3.3, one way a DR participant could use a STFM would be to be fully hedged well in advance and then to repackage and resell a share of its hedge in the STFM. There are several ways a DR could utilise a STFM, each with its own complexities. Table 5.1 below outlines some options for DR participants to use a STFM.

Table 5.1: Possible demand response uses for a STFM

OPTION	USE OF STFM	DETAILS
On-sell product directly	A fully hedged DR participant could on sell a product, such as a cap, that it will no longer use (e.g. the amount of load it is willing to shed) onto the STFM.	This could entail the DR participant writing a new, or novating an existing, contract to the market. While a STFM could reduce the uncertainty for a participant to implement its DR, it may also imply it is over-hedged.
Sell back the hedging product	If the hedging product is an OTC contract, the demand response participant could sell the hedging product back to the original counterparty, who could in turn sell the product on the STFM.	This method would not require the demand response participant to invest in the systems or prudentials required for the STFM. However, this may be limited to OTC contracts and would require both parties of the original contract to be willing to participate.
Respond to STFM price signal	A demand response participant who is not fully hedged could use the price signal of a STFM to inform its demand response decisions (i.e. the value of selling demand response compared to the value of lost production).	This method would not directly use the STFM or improve the liquidity on the STFM. Further, a demand response participant could currently use pre-dispatch price estimates to do this.

Separately, the Commission is considering several mechanisms to support demand response mechanisms.[19] The introduction of a STFM has the potential to serve to complement such a mechanism and, to a lesser extent, partially substitute the potential requirement for such a mechanism.

18 Five minute settlement will be introduced on 1 July 2021. This is a change from the current 30-minute settlement, where the price paid/received by participants in the average of six, five minute periods. For more information see: https://www.aemc.gov.au/rule-changes/five-minute-settlement.

19 For more information see: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

QUESTION 3: CURRENT RISK MANAGEMENT FOR END USERS

3a) How do end users currently manage their short term spot price risk? Are there any OTC products or financial products such as weather derivatives that are currently used to minimise short term risk?

3b) Would a STFM assist end users in managing risk? If so how, in particular given the expectation that short term contract prices will approach the spot price closer to the delivery period? What products would be beneficial to be listed?

3c) Would the introduction of a STFM be beneficial to demand response participants? If so, how? What would be the best way for a demand response participant to maximise benefits from the introduction of a STFM?

3d) What design elements should be considered in considering possible interactions between a STFM and wholesale demand response mechanism?

3e) Are there any benefits for introducing a STFM, outside those mentioned in this consultation paper?

5.2 Market design

There are several design elements of a STFM that will affect the benefits it provides. They include:

- the operator of the STFM
- the participants in the market
- the products listed on the exchange
- the prudential requirements and treatment of credit risk
- the level of integration with AEMO systems.

As a decision on an individual element may have implications for the choice of other elements, rather than receiving feedback on different models, the Commission is requesting comment on each element individually.

5.2.1 Operation of the STFM

In the rule change request, the proponent suggested the STFM would be operated by AEMO, and linked to AEMO's settlement and clearing processes. Another option not put forward in the rule change proposal would be to open the operation of the market up to another third party, or to run an auction to determine who would operate the market. Currently, the ASX has the systems and processes established to offer short term financial contracts. Additionally, Financial and Energy Exchange (FEX) Group has attained a licence from the Australian Securities and Investments Commission (ASIC) to start trading Australian financial derivatives.[20] If this new exchange enters the market, it could also offer these shorter term

20 For more information see: https://fex.com.au/aboutfexgroup.shtml

electricity products. While the ASX currently has the ability to offer short term electricity derivatives, it is yet to do so. This suggests if a third-party were to operate a STFM, it may require an incentive to do so.

The Commission may not have sufficient rule-making power under the NEL to introduce an STFM operated by a party other than AEMO or otherwise make a rule that provides for an auction to determine who operates the market. There may also be limitations in implementing these alternatives as a result of AFSL requirements and the application of other regulatory arrangements outside of the national electricity framework. These matters will be considered by the Commission as part of the rule change process.

QUESTION 4: OPERATION OF A STFM

4a) What are the comparative costs and benefits of AEMO operating a STFM versus a third-party? Should this assessment be made by market bodies or a market process (such as an auction)?

4b) If a third party were to operate the STFM, what level of incentive would be required, and who should pay?

5.2.2 Market participants and liquidity

The Moomba GSH is currently experiencing a lack of liquidity with minimal trades on the hub, as noted in appendix a.1.[21] If a similar issue were to arise in the STFM it may result in one-off or on-going costs being borne by AEMO, and in turn participants, with little corresponding benefit. Therefore, the design of the market should maximise the probability of sufficient liquidity and trades in the market, while minimising the entry and transaction costs.

One option, not raised in the rule change request, to improve liquidity would be to open participation in the STFM to any party with the correct licensing and approvals, such as financial intermediaries. This would encourage non-physical participants (namely, persons other than generators and market customers) to enter the market, providing additional capital and trade in the products. This additional trade may encourage more participation in the market, improving liquidity and reducing costs for physical participants.

The Commission’s preliminary view is that it is unlikely to have sufficient rule-making power under the NEL to introduce an STFM in which financial intermediaries are able to participate.[22] The Commission will consider the matter further as part of the rule change process.

21 In 2017 there were 2 trades (12 TJ); in 2018 there were 10 trades (76TJ); and in January 2019 there were 3 trades (30TJ) on the Moomba GSH.

22 More specifically, in the present context the Commission does not consider that it has sufficient rule-making power to make a rule that regulates persons who are not: (a) participating in the wholesale exchange operated by AEMO (i.e. participating in the electricity spot market); or (b) otherwise involved in the operation of the national electricity system (i.e. the national interconnected grid).

Another element that affects the level of liquidity is the type of products listed on the exchange. The rule change proposal suggests the product tenure range from a week ahead of the trading day to a day ahead of the trading day. However, depending on what is useful for participants, additional variations could be introduced. Additionally, there was limited comment in the rule change proposal on the specific type of product that is listed. For example possible products include flat, peak, off-peak and super peak swaps, and or caps/other option contracts. The process for determining what products are listed and how products are added or removed needs to be determined.

QUESTION 5: MARKET PARTICIPANTS AND LIQUIDITY

5a) Which parties should be allowed to participate in the STFM? What would be the impact on the benefits and costs of an STFM if only market participants (notably, generators and market customers) could participate in the market?

5b) What products should be offered on the market, additional to those previously suggested? What should be the process for adding/removing products?

5.2.3 Integration of the STFM

Another important design element is the level of integration with AEMO's existing settlement and prudential systems. The rule change proposal suggests there may be efficiency benefits from integrating the STFM with the elements of the existing reallocation, settlement, clearing and prudential systems operating in the NEM spot market. Varying levels of integration would need to be tested for feasibility and costs verses benefit.

One example of a possible integration is to reallocate STFM contract positions to the daily outstanding amount – a position usually managed through trading activity or cash, if limits are at risk of being breached.[23] This is comparable to a smaller scale version of the reallocation facility AEMO provides for parties to assign their side of a bilateral OTC contract to their spot market prudential position.[24]

Another area of potential integration to AEMO's existing systems could involve settlements — the calculating and issuing of invoices and receipts based on trading transactions. The settlement statements used in the NEM might be able to include STFM positions which could reduce circular cash flows, if STFM settlement positions are offset against NEM settlement spot market position.[25]

Similarly, a STFM may be able to leverage existing clearing processes which facilitate the transfer of money between AEMO and participants. AEMO currently uses the Austraclear service provided by the ASX. Subject to ascertaining AFSL requirements, the centralised settlement service might be able to accommodate a STFM.

23 See NER rule 3.3.9 'Outstandings'.

24 CS facility licence exemption granted to AEMO in respect to swap and offset allocation (notice under section 820C of the Corporations Act 2001 (Cth) 23 February 2016).

25 See NER Rule 3.15 'Settlements'

The treatment of credit risk and prudentials are also paramount to the design of the market. AEMO's prudential requirements refer to the credit support provided to protect participants in the instance a market participant becomes insolvent, and unable to fulfil its financial commitments. AEMO's prudential requirement has two components:

- the outstandings limit, which in general terms is the payment accrual for a 35-day period which a participants trading must stay within[26]
- the prudential margin, which in general terms is a buffer that must be maintained at all times between the maximum credit limit[27] and the outstandings limit for each Market Participant. It is in place to cover the seven day period that would be needed to cover payments while managing a participant default event.

There are several options available for the treatment of prudentials for an AEMO-operated STFM, and each may have its own benefits and drawbacks. STFM prudentials could be:

- pooled, to various extents, with NEM spot market prudentials, so that the two markets are treated as one larger market
- pooled with the GSH market prudentials, with both markets proposed to be operating on Trayport
- established independently as an individual market.

It should be noted that under any option, the credit risk does not entirely dissipate, so additional collateral may need to be provided. Further, there may be legal requirements that dictate which treatment of prudentials is implemented for a STFM.

The decision about the operator of the STFM will necessarily affect subsequent decisions on integration of systems. For example if a third-party were to operate the STFM, it would not be able to integrate with AEMO systems, but may be able to integrate with the settlement and prudentials of other financial products. Additionally, each decision on system integration will impact the cost of the project.

As part of its assessment of the rule change, the Commission will need to consider whether any integration of an STFM into the existing settlement and prudential arrangements of the NEM is consistent with the NEL, AEMO's statutory immunities under the NEL (if AEMO were to operate the market) and what impact regulatory arrangements outside of the national electricity framework (e.g. the *Payment Systems and Netting Act 1998* (Cth)) would have on the implementation of such an integrated STFM.

QUESTION 6: INTEGRATION OF STFM

6a) Will there be cost savings to participants by using AEMO's systems as opposed to a third

26 More specifically, it is AEMO's estimate of the maximum value a market participant's liability (or outstanding) can reach over the payment period.

27 The maximum credit limit is the minimum amount of credit support the participant is required to provide to AEMO, for which there is no more than a 2% probability that, were that participant to default, its credit support would be insufficient to fully meet the liabilities it owes to the spot market

party? If so, what systems should the STFM integrate into?

6b) Under an AEMO-operated STFM, is there a specific prudential treatment that would be beneficial to participants? How would this differ to an ASX-operated STFM? How could the choice between prudentials in each market affect the participation in a STFM? Would options that allow leveraging of existing prudentials for use in the STFM increase the prudential risk or default risk that AEMO is managing?

5.3 Implementation costs

In assessing design choices of a STFM, the Commission is cognisant that there is a risk that if a STFM had low levels of utilisation, the costs of establishing the market would be incurred, but without the benefits being realised, which would not be in the long term interest of consumers. Some potential costs of implementing a STFM, assuming AEMO's proposed design, include:

- Trayport platform costs for AEMO and licensing for participants
- AEMO update of systems and processes, which could be dependent on the level of integration with existing systems
- legal/consultant fees to design products for the exchange
- STFM participation fees to cover the operating costs of the exchange
- any education and training of participants that is required.

As noted in the proponent's request (and above in section 3.4), depending on the design of an STFM and the products traded, AEMO and participants in the market may need to obtain an AFSL (or an exemption) under the Corporations Act 2001 (Cth).[28] If the products traded on the market are financial products for the purposes of the Corporations Act, an AFSL or exemption will need to be obtained by market participants (if they do not already hold a licence) and AEMO may need to obtain a licence or exemption to operate the market. Prospective participants may not be able to obtain a licence (or it may be overly costly), which may limit participation in the market. The timing of obtaining any licence or exemption to operate the market may also impact on the ability, and costs associated with, effectively implementing an STFM under the NER. Further, the application of other regulatory frameworks beyond the national electricity framework (e.g. the *Payment Systems and Netting Act 1998*) may impact on the costs associated with implementing any STFM. The Commission will need to consider such matters as part of the rule change process.

QUESTION 7: IMPLEMENTATION COSTS

7a) What are the likely types of costs (and scale of those costs) incurred from the

28 AEMO, Short term forward market rule change proposal, p.4-5.

introduction, and operation of, the STFM proposed by AEMO (and other potential models)?

7b) Would the requirement to attain an AFSL be a significant barrier to operating in the STFM?

7c) If the STFM were to be implemented, what other operational and implementation issues may arise? How much time is required for market bodies and participants to prepare for the introduction of an operational STFM?

7d) Is the proposed assessment framework appropriate? Should any criteria be added or removed?

6 LODGING A SUBMISSION

Written submissions on the rule change request must be lodged with Commission by 23 May 2019 online via the Commission's website, www.aemc.gov.au, using the 'lodge a submission' function and selecting the project reference code ERC0259.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change requests.[29] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Prabpreet Calais on (02) 8296 0605 or Prabpreet.Calais@aemc.gov.au.

29 This guideline is available on the Commission's website www.aemc.gov.au.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFSL	Australian Financial Services Licence
ASIC	Australian Securities and Investment Commission
ASX	Australian securities exchange
Commission	See AEMC
CTP	capacity trading platform
DAA	day-ahead auction
DR	demand response
FEX	Financial and energy exchange
GSH	gas supply hub
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
OTC	over-the-counter (contract)
PPA	power purchase agreement
PRS	proxy revenue swap
RFR	Reliability framework review
STEM	short term energy market (WA)
STFM	short term forward market
VRE	variable renewable energy
WEM	wholesale electricity market (WA)

A OTHER AEMO OPERATED EXCHANGES

In the east coast gas market, AEMO currently operates two exchanges that list ahead products, namely:

- the Gas Supply Hubs at Wallumbilla and Moomba, are exchanges for physical gas
- the Capacity Trading Platform and day-ahead auction, which is an exchange for unused pipeline capacity.

While these markets are different to the NEM, they do provide context as to what a short term forward market could look like if implemented.

A.1 Gas supply Hubs

The Gas Supply Hubs (GSHs) are a gas trading exchange for trading natural gas and related services including a pipeline capacity listing service. There are two GSHs operating on the east coast, one at Wallumbilla established in March 2014 and one at Moomba established in June 2016. The GSH operates a voluntary net-pool trading exchange, through which participants can trade standardised short-term physical gas products on an electronic platform called Trayport. AEMO centrally settles transactions on Trayport, manages prudential requirements and produces reports which assist participants in managing their portfolio and gas delivery obligations. Participants are responsible for the delivery of gas traded to the location of the hub. The Wallumbilla hub consists of three foundation pipelines — Roma-Brisbane, South West Queensland, and Queensland Gas Pipeline — and the Moomba hub has two foundation pipelines — Moomba-Adelaide, and Moomba-Sydney.

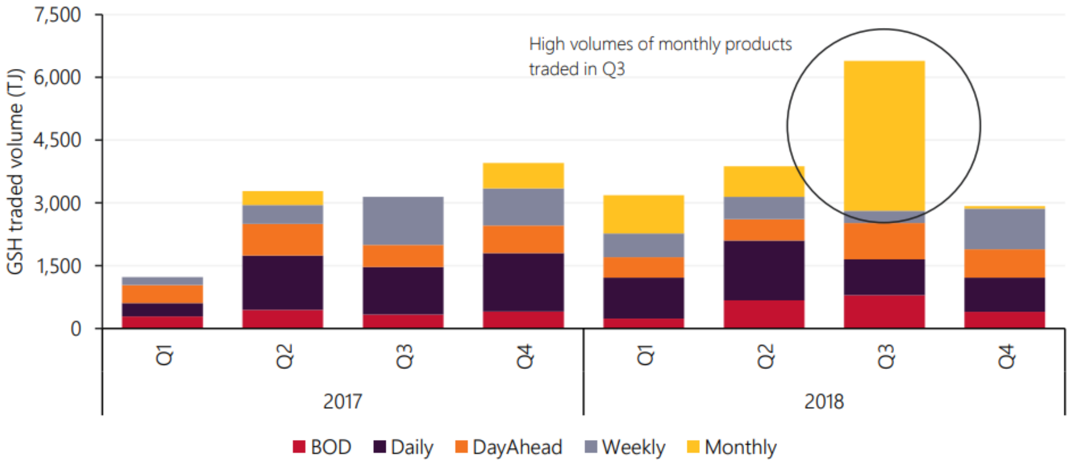
The GSHs list the following products:

- balance-of-day
- day-ahead
- daily
- weekly
- monthly.

Currently, the two hubs have different levels of liquidity. The Moomba exchange has had very low levels of trading, whereas the Wallumbilla exchange is actively used by participants.[30] Figure A.1 below illustrates the spread of products traded on the Wallumbilla exchange in 2017 and 2018.

30 In June 2018, the AEMC released its Biennial review into liquidity in wholesale gas and pipeline trading markets, which examines liquidity on the GSHs, DWGM and Short Term Trading Markets in greater detail using both quantitative and qualitative metrics. Please see for more information.

Figure A.1: **GSH traded volume by product**



Source: AEMO, Quarterly Energy Dynamics — Q4 2018, p. 26.
Note: For relativity, the total gas demanded across both the Short term trading markets and the declared wholesale gas market in Q4 2018 was 62,000 TJ. The GSH contributed around five per cent of total gas demand.

A.2 Pipeline capacity mechanism

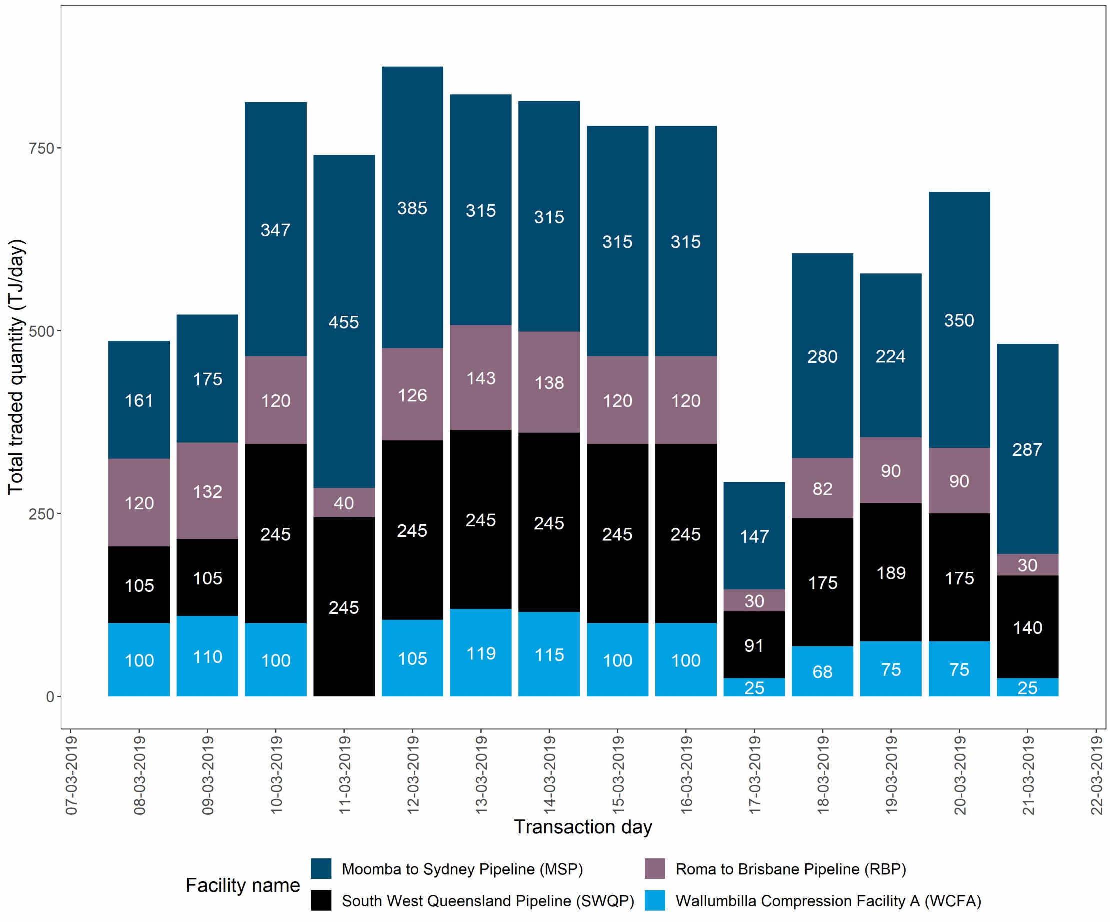
The pipeline capacity trading reform package was implemented on 1 March 2019 to enable participants to obtain more flexible and competitive pipeline capacity between the GSHs by developing a market for secondary trading of pipeline capacity.

The reform package included:

- the introduction of a day-ahead auction of contracted, but un-nominated pipeline capacity to be conducted shortly after nomination cut-off
- standardised provisions in capacity agreements to make capacity more fungible and allow shippers greater receipt and delivery point flexibility
- the development of a pipeline capacity trading platform (CTP) through which shippers could trade secondary capacity ahead of the auction
- the requirement to publish information on secondary trades of capacity and hub services.

The CTP also operates on Trayport, which enables participants to streamline their purchase of both gas commodity and pipeline capacity, potentially driving increased utilisation of both. While the CTP and day-ahead auction have not been operating for a long, initial data suggests that most of the capacity has been cleared through the day-ahead auction, and cleared around the auction floor of $0. This may change as more participants become familiar with the dynamics of the new market. Figure A.2 illustrates the traded volumes on the day-ahead pipeline capacity auctions.

Figure A.2: Total traded quantity on day-ahead auctions



Source: AEMC analysis of AEMO data

For both the GSH and the CTP, AEMO charges fees to participants including a fixed annual fee and a variable fee on each trade. The fixed fee for the GSH is $12,000 per annum, and if a participant chooses to trade on both the GSH and CTP they only pay for using the GSH. The fees for partaking in the CTP are listed in Figure A.3.

Figure A.3: Participant fees for the Pipeline capacity trading mechanism

Fee	Fee Type	1 March-30 June
Capacity Trading Platform (CTP)	Fixed Fee - one licence per annum (commodity & capacity)	12,000
	Fixed Fee - one licence per annum (capacity only)	7,000
	Variable fee ($/GJ)	
	- Daily product fee ($/GJ)	0.043
	- Weekly product fee ($/GJ)	0.033
	- Monthly product fee ($/GJ)	0.023
Day ahead Auction (DAA)	Variable fee ($/GJ)	0.033

Note: the variable fee for CTP and DAA includes a fee of $0.003 relating to OTS code panel

Source: AEMO 2019, Pipeline Capacity Trading: AEMO budget and fees, p. 2.
Note: OTS stands for operational transportation Service code