Review of Vesting Contract Regime

A FINAL REPORT PREPARED FOR THE ENERGY MARKET AUTHORITY

September 2016

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Glossary

Term	Definition
BVQ	Balance Vesting Quantity
CC	Contestable Customers
CCGT	Combined-Cycle Gas Turbine
CfDs	Contracts-for-Differences
EMA	Energy Market Authority
EMC	Electricity Market Company
FRC	Full Retail Competition
Gencos	Generation Companies
GRF	Generation Registered Facility
GSF	Generation Settlement Facility
HHI	Herfindahl Hirschman Index
HHV	Higher Heating Value
HSFO	High-Sulphur Fuel Oil
LNG	Liquified Natural Gas
LRMC	Long Run Marginal Cost
MCR	Market Clearing Engine
MPC	Market Price Cap
MSSL	Market Support Services Licensee
MSSL load	Load relating to customers who are presently non-contestable
NCC	Non-Contestable Customers
NEMS	National Electricity Market of Singapore
OCGT	Open-Cycle Gas Turbine
PNG	Pipeline Natural Gas
PSO	Power Services Operator
PST	Pivotal Supplier Test
SGX	Singapore Exchange Ltd
SPARK	Frontier Economics' market model
SPS	SP Services
SRMC	Short Run Marginal Cost
SWEM	Singapore Wholesale Electricity Market
TOP	Take-or-Pay (in relation to gas contracts)
ToR	Terms of Reference
USEP	Uniform Singapore Energy Price
VC	Vesting Contract
VCL	Vesting Contract Level
VoLL	Value of Lost Load

Executive summary

The Energy Market Authority (EMA) appointed Frontier Economics to undertake a review of the mechanisms used to mitigate market power in the Singapore Wholesale Electricity Market (SWEM), including:

- Reviewing the vesting contract level (VCL) for 2017 and 2018
- Reviewing the existing vesting contracts regime
- Reviewing the international experience in market power mitigation
- Developing new mechanisms to mitigate market power in the SWEM.

Frontier Economics' draft report Review of the Vesting Contracts Regime (the draft report) was released on May 16, 2016. EMA received a number of submissions commenting on the draft report from a range of interested parties.

Frontier Economics' revised report was released on August 31, 2016 in conjunction with the EMA's draft determination. A second round of submissions were made in response to the revised report.

This final report discusses the comments raised in both rounds of submissions and Frontier Economics' response to the comments. Where appropriate the discussion in the report has been updated to reflect the submission comments. However, our recommendations remain substantially unchanged.

Comments on the draft and revised reports

In summary, Senoko Energy, Tuas Power and YTL PowerSeraya were not supportive of the balanced market approach recommended in the draft report and confirmed in the revised report, while the remaining industry players supported or did not comment on the recommendation. Senoko Energy, Tuas Power and YTL PowerSeraya argue that the Review was narrowly focused on the use of vesting contracts to achieve the objective of mitigating market power, and propose to increase the VCL to ensure financial sustainability of generation businesses.

In contrast, the remaining market participants were largely in favour of the balanced market approach, although there was some divergence of opinion regarding the preferred timing, approach to hedging unvested MSSL load and necessity of arrangements for managing price separation. In particular, some participants suggested a gradual adjustment in the VCL while other participants recommended an immediate rollback to LNG vesting level. PacificLight Power, Keppel and SembCorp raised concerns about nodal price separation, and suggested a range of mechanisms to manage those issues.

Several other issues were raised in the submissions, including the scope of the review, the methodology for allocating vesting contracts between generators, the proposed 25% capacity share cap, details regarding the implementation of various other recommendations and the modelling approach and results. We discuss the comments raised in both rounds of submissions, and Frontier Economics' response to the comments, in more detail at the beginning of the relevant Section and Appendix of this final report.

Review framework

Market power can be defined strictly as the ability of sellers to profitably alter prices away from competitive levels. Other things being equal, a generator's incentive to exercise market power by engaging in withholding strategies is directly correlated with its exposure to the wholesale price. Hedging a generator's exposure to the wholesale price – via vesting contracts, tender vesting, other bilateral contracts, futures contracts or retail contracts – reduces pool price exposure and therefore mitigates a generator's incentives to exercise market power.

We have evaluated the current vesting contract regime and alternative market power mitigation measures against the following criteria:

- Effectiveness: of a measure in curbing market power at both a market-wide level and at a localised level
- Dispatch efficiency: whether a measure promotes merit-order dispatch
- Resource adequacy: whether a measure promotes efficient investment, retirement and innovation decisions i.e. dynamic efficiency
- Intrusiveness and administrative burden: the onerousness and cost of a measure to participants, the market operator and the EMA
- Transparency and predictability: whether the measure operates in a manner that actual and prospective participants can reasonably anticipate.

Review of VCL

Under the EMA Procedures, the VCL must be reviewed biennially. The Procedures provide that the VCL is set primarily to curb the market power of the generators "to an acceptable level" and to encourage the spot market price "not to average above long-run marginal cost (LRMC)". In setting the VCL, the EMA is required to balance the following factors:

- Expected LRMC of a new entrant combined cycle gas turbine plant
- Supply and demand projections
- Robustness of different contract levels to data uncertainty
- Likely data scenarios, including the potential range of plant configurations
- Avoidance of frequent fluctuations in the VCL through a monotonic rollback schedule, if possible.

We modelled a wide range of potential VCLs for 2017-18, from 35% down to the LNG vesting level, utilising our strategic bidding and dispatch model, *SPARK*. *SPARK* is a plant dispatch model that utilises game theory to identify sets of generator bidding strategies that yield Nash Equilibria. For each VCL, our modelling considers the case where unvested MSSL load was either hedged (via tender or otherwise) or unhedged (such that the pool exposure of the Gencos increased).

We modelled the impact of different VCLs across the following scenarios, allowing for generator forced outages to occur stochastically in all cases:

- A base case scenario, incorporating standard assumptions of demand and plant availability
- A bidding sensitivity scenario, where we assumed that both steam and OCGT units were offered into the market at $350/MWh and
- A supply-demand sensitivity scenario, where we tightened supply-demand conditions by assuming that the growth rate for energy/peak demand doubled and that around half of the steam units were removed from the market.

In the base case, our forecasts indicate that prices are unlikely to rise significantly if the VCL were lowered, whether or not the unvested MSSL load is hedged.

In the bidding sensitivity case, where unvested MSSL load is unhedged, we observe material rises in forecast prices (though still not in the order of LRMC). Where the unvested MSSL load is hedged, we observe no material price increases when dropping the VCL to 20%. However, we do observe minor price increases when further dropping the VCL to the LNG vesting level.

In the supply-demand sensitivity case, assuming the MSSL load is prudently hedged, we found some cases where a lower VCL would lead to higher forecast prices. However, prices did not approach LRMC, despite being generally higher and more volatile in all VCL cases.

In light of limited evidence for the likely exercise of market power in the near term, we consider that there is scope to reduce the VCL to the LNG vesting level by the end of calendar year 2018 if the MSSL load is prudently hedged. If the unvested MSSL load is not hedged, we propose the VCL should not be reduced below 20%.

Recommendation 1 – VCL for 2017 & 2018

We recommend that, conditional on prudently hedging the unvested MSSL load, there is scope to reduce the VCL to the LNG vesting level by the end of calendar year 2018.

If the unvested MSSL load is not hedged, we recommend that the VCL be reduced to no lower than 20% for calendar years 2017 and 2018.

Review of the current vesting regime

All else equal, a higher VCL should mitigate the generators incentives to exercise market power. A simple analysis of recent spot market outcomes suggests that, to date, the vesting contract regime has been effective in mitigating market power. However, spot market outcomes are influenced by a range of factors other than vesting contracts, including the supply-demand balance and the take-or-pay gas commitments of market participants. A market design that effectively constrains the exercise of market power will typically also promote dispatch efficiency.

Regarding resource adequacy, we consider that the vesting regime does not systematically prevent generators from recovering efficient costs. However, linking the allocation of vesting quantities to licensed capacity offers perverse incentives for generators to keep inefficient plant in service and to oppose efficiency-enhancing reforms.

The essential character of vesting contracts is that they are imposed on market participants. Vesting contracts therefore represent a relatively intrusive measure for mitigating market power. The design and operation of vesting contracts also involves a degree of complexity and administrative burden on participants, market operators and policy-makers. For these reasons, vesting contracts are usually authorised as a time-limited mechanism in most of the markets where they have been applied.

The current vesting regime in the SWEM operates in a reasonably transparent manner. However, there is significant uncertainty associated with the biennial resetting of the VCL. Minor incremental enhancements could be made to the current vesting regime to provide greater certainty to market participants about proposed changes to the VCL.

International review of market power mitigation mechanisms

We reviewed the mechanisms used to mitigate market power in a range of international electricity markets. This included the energy-only markets operating in Australia, New Zealand and Texas. We also considered the energy and capacity markets in PJM (in the United States) and Ireland. We also considered particular features of the energy-only market in Alberta, and the energy and capacity market in Western Australia. We found that the design of a market necessarily influences the type of market power mitigation mechanisms observed in that market.

Our review identified and assessed a range of tools used internationally to mitigate market power – these are:

- Conditional price caps, including:
  - Scarcity pricing (used in New Zealand)
  - Cumulative price threshold caps (Australia).
- Bidding restraints and obligations, including:

  - Mandated SRMC bidding (Ireland and Western Australia)
  - Pivotal supplier tests (PJM and Texas)
  - Voluntary mitigation plans (Texas)
  - General behavioural obligations (Australia and New Zealand).
- Other mechanisms, including:
  - Capacity or concentration caps (Alberta, and more generally in the United States)
  - Directed contracts (Ireland).

A number of these mechanisms are not suitable for Singapore. Conditional price caps are unlikely to be effective in mitigating market power in the SWEM. Bidding rules imposed in capacity markets, such as a requirement for generators to bid at short-run marginal cost, are not appropriate for Singapore's energy-only market. Voluntary mitigation plans are likely to have limited efficacy in mitigating market power, and general behavioural obligations on generator bidding have proved problematic in Australia and New Zealand.

A number of tools may be useful for managing market power in the SWEM, and have been considered in more detail as part of our review. Pivotal supplier tests are successfully applied to manage localised or transient market power relating to transmission constraints. Capacity or concentration caps present a relatively unobtrusive method for preventing structural market dominance. The concentration model applied to determine the level of directed contract cover in Ireland may provide a more transparent and mechanistic approach to determining the VCL.

Alternative mechanisms for mitigating market power

We have designed a series of alternative 'packages' for mitigating market power in the SWEM. Each package was developed by combining various features of the current regime and the mechanisms applied in other jurisdictions. The packages are as follows:

- The **status quo** refers to the current arrangements for mitigating market power in the SWEM, including the existing vesting contract regime, the capacity caps applying to the three largest generators via their generation licences and the EMA's monitoring and investigation powers under the *Electricity Act*. We recommend some relatively minor changes to these status quo arrangements.
- The **improved vesting contract regime** involves incremental changes to address some of the key shortcomings associated with the status quo:

  - the capacity caps applying to the three largest generators are replaced with capacity market share caps in *all* commercial generation licences (with a transition path)
  - the current discretionary approach to setting the VCL is replaced by a more mechanistic approach to improve transparency and predictability
  - the allocation of the VCL is gradually changed to reflect the effective capacity of generators, accounting for existing market positions
  - the unvested MSSL load would be prudently hedged via a combination of SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

- In the **balanced market regime**, capacity caps would also be replaced by capacity market share caps across all generators. However, vesting contracts would be gradually reduced to LNG vesting level and then reduced to zero at the expiry of LNG vesting. All unvested MSSL load would be prudently hedged, as for the improved vesting regime.
- The **combined approach** contains all the same elements as the balanced market package while adding a pivotal supplier test (together with an increased market price cap) to manage instances of localised market power.

Comparing the new arrangements

We consider that the **improved vesting contract regime** would improve the efficacy of the arrangements in the longer term compared to the status quo. Although vesting contracts remain in place as the primary mechanism to mitigate market power, a revised contract allocation and the introduction of a requirement to hedge unvested MSSL load should improve the effectiveness of the arrangements in managing market power and improve dispatch efficiency. The reallocation of the vesting contracts improves incentives for resource adequacy relative to the status quo, while the mechanistic approach to determining the VCL improves transparency and predictability. However, under this regime relatively intrusive vesting contracts would be entrenched as a feature in the SWEM.

The light-handed approach to managing market power under the **balanced market regime** results in the most positive assessment compared to the status quo and other alternatives. The phasing out and ultimate removal of vesting contracts under this approach avoids the intrusiveness, administrative burden, and lack of transparency and predictability associated with the status quo. Prudently hedging the unvested MSSL load acts as an effective mechanism to mitigate market power and enhance dispatch efficiency. While the balanced market approach is less effective than the alternatives in managing localised market power, it is not clear that localised market power is, or is likely to become, a significant issue in the SWEM.

The introduction of a pivotal supplier test under the **combined approach** improves the management of localised market power compared to the balanced market approach. The negative impact that a pivotal supplier test may have with regard to resource adequacy, by reducing the frequency and extent of high price events in the SWEM, is offset by raising the market price cap. As in the balanced market package, the phasing out and ultimate removal of vesting contracts under the combined approach improves resource adequacy and transparency and predictability compared to the status quo. However, the introduction of a pivotal supplier test represents a relatively intrusive modification to the market design and is likely to involve significant development costs.

On balance, and noting the range of comments made by market participants in their submissions, we continue to recommend the balanced market regime. We consider the package of measures under the balanced market approach to be the most effective, least intrusive and most transparent and predictable way to mitigate market power in the SWEM. We accept participant comments that the approach to be used for hedging unvested MSSL load should not be mandated, and have therefore amended our recommendation to ensure there is flexibility in the hedging strategy.

Recommendation 2 – Balanced market regime

We recommend the introduction of the balanced market regime to manage market power in the SWEM, comprising:

- Retaining the EMA's existing market monitoring and *Electricity Act* responsibilities.
- Replacing the capacity caps in the generation licences of the three largest Gencos by a 25% market share cap in all generation licences in a manner that does not force divestments under the current generation licences.
- Phasing out vesting contracts in several stages. First, gradually reducing balance vesting quantities to LNG vesting. Second, removing all vesting contracts once LNG vesting contracts have expired.
- Prudently hedging the unvested MSSL load.

Transitioning to the new arrangements

We note the range of comments from market participants in their submissions about the optimal approach to transitioning to the new arrangements. Nevertheless, we continue to recommend the transition from the status quo to any new regime proceeds in a staged and orderly manner to allow appropriate enabling arrangements to be developed and ensure market participants are able to adjust their portfolios as required. We therefore advocate a gradual transition to the new arrangements over two to three years. In terms of the approach to hedging, and once again noting participant comments on this issue, we recommend the unvested MSSL load should be hedged via a combination of SGX products, tenders and bilateral trades. . We expect hedging via the SGX will become an increasingly important tool for hedging MSSL load as the market matures.

Recommendation 3 – Transition path

We recommend a gradual adjustment from the status quo to the new arrangements over 2 to 3 years, taking into account the changes that may be required to support the new arrangements and the objective of ensuring an orderly transition.

The hedging of unvested MSSL load could involve a combination of SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

1 Introduction

Frontier Economics is pleased to provide this report to the Energy Market Authority (EMA) setting out our advice on the current vesting contract regime, and potential new mechanisms to mitigate market power in the Singapore Wholesale Electricity Market (SWEM).

1.1 Background

The EMA introduced vesting contracts in the SWEM on 1 January 2004 for the purpose of controlling the market power of the generation companies (Gencos), in order to promote efficiency and competition in the electricity market for the benefit of consumers.[1]

Vesting contracts are electricity hedging instruments imposed on market participants by policy-makers or regulators, usually coinciding with reforms undertaken to establish wholesale electricity markets. In Singapore's case, the vesting contracts consist of two-way 'contracts for differences' (CfDs) between the vested Gencos and SP Services (SPS) as the market support services licensee (MSSL), that hedge a specified amount of electricity at an agreed price. The imposition of such contracts reduces the exposure of the vested Gencos to spot market prices, and hence reduces their incentives to exercise market power by withholding or re-pricing their capacity to push up spot prices in the SWEM.

The EMA appointed Frontier Economics to conduct a review of the vesting contract regime, and to consider how market power could be effectively mitigated in the future (the Review). The vesting contracts regime may either co-exist with or be replaced by alternative mechanisms to mitigate market power. The scope of this study is discussed in Section 2 below.

Frontier Economics' draft report *Review of the Vesting Contracts Regime* (the draft report)[2] was released on May 16, 2016. EMA received a number of submissions commenting on the draft report from a range of interested parties.

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1 See the EMA website at: https://www.ema.gov.sg/Licensees_Electricity_Vesting_Contracts.aspx (accessed 8 February 2016). This link provides access to a number of documents including: EMA, *Frequently Asked Questions on Vesting Contracts*, July 2007, response to question 1 and EMA, *EMA's Procedures for Calculating the Components of the Vesting Contracts*, Version 2.1, December 2013 (EMA Procedures), p.1-1.

2 Frontier Economics, *Review of the Vesting Contracts Regime*, Draft report, May 2016.

Frontier Economics' revised report[3] was released on August 31, 2016 in conjunction with the EMA's draft determination. A second round of submissions were made in response to the revised report.

This final report discusses the comments raised in both rounds of submissions, responds to those comments and, where appropriate, updates our analysis and recommendations.

1.2 About this report

This report is structured as follows:

- Section 2 outlines the scope for the Review.
- Section 3 presents the analytical framework applied to the Review. It defines what market power is, and outlines the evaluation framework used to assess the vesting contracts regime and alternative mechanisms for mitigating market power.
- Section 4 assesses the existing vesting contracts regime, which is currently the primary mechanism for managing market power in the SWEM, highlighting elements that are working well and identifying potential shortcomings.
- Section 5 outlines a range of alternative tools that could be used to mitigate market power in the SWEM, based on the design of market power mitigation mechanisms employed in other jurisdictions.
- Section 6 formulates, describes and assesses several 'packages' of measures for mitigating market power in the SWEM in the future, with each package incorporating one or more of the following:
  - the current vesting contract regime and potential variations thereto (Section 4) and
  - alternative market power mitigation tools derived from our review of international experience (Section 5).
- Section 7 presents our recommendations and conclusions.

Additional detail is provided in a series of Appendices:

- Appendix A sets out our international review of market power mitigation mechanisms.

3 Frontier Economics, *Review of the Vesting Contracts Regime*, Revised report, September 2016.

- Appendix B describes our electricity market model, *SPARK*, which was used to inform our assessment of the existing vesting regime and packages of alternative market power mitigation tools.
- Appendix C presents the input assumptions used in our market modelling.
- Appendix D describes the market modelling calibration process and presents the calibration outputs.
- Appendix E includes the quantitative analysis that underpins our recommendations, describing the methodology used and presenting the results for each of the market power mitigation tools.

2 Scope of this Review

This Section considers the scope of the Review. Participant comments on this section of our draft report are discussed in Section 2.1. Section 2.3 outlines the Terms of Reference (ToR) provided to Frontier Economics. Section 2.4 addresses some preliminary comments made by the three incumbent Gencos regarding the ToR.

2.1 Comments on the draft report

Several participants comment on the scope of the Review. In particular, the three incumbent Gencos comment that the scope of the Review was too narrow. Senoko Energy, Tuas Power and YTL PowerSeraya state that vesting contracts are intended to achieve a range of policy objectives beyond the mitigation of market power, including providing a stable price path for non-competitive customers, underwriting demand for LNG, and providing financial stability for market participants. In response, the EMA reiterate that the vesting contracts are intended to mitigate market power rather than achieve other policy objectives, hence the focus of the Review.

2.2 Comments on the revised report

Participants continue to comment on the scope of the Review. YTL PowerSeraya and Senoko comment that vesting has been used in the past to promote the uptake of LNG, not only manage market power, and it is therefore appropriate to use vesting contracts to manage issues associated with financial sustainability. Senoko suggests consideration should be given to measures outside of the vesting contract regime that could promote financial viability to preserve key infrastructure and avoid market disruption. In response we note, once again, the EMA's guidance that the scope of this Review is focused on the mitigation of market power to enhance market efficiency, taking into account dispatch efficiency, generation resource adequacy in the long term, transparency and predictability, as well as the intrusiveness and administrative burden of various options compared to the status quo.

2.3 Terms of Reference

The EMA appointed Frontier Economics to undertake the Review comprising a series of tasks. The Review is focused on assessing the effectiveness of the current vesting contracts regime and potential alternative arrangements for mitigating market power in the SWEM. Table 1 sets out the key tasks, and the Section of this report that addresses each of these tasks.

Table 1: Terms of reference for this review

Elements	Section
Review of international experience in market power mitigation • Review of market power mitigation approaches/mechanisms in comparable electricity markets in other countries, including Australia, Texas, PJM, New Zealand and Ireland. • Detail the relevant principles and learning points.	Appendix A and Section 5
Review of vesting contracts regime • Review the efficacy of the existing vesting contracts regime given its objective of mitigating the market power of Gencos in the SWEM. • Recommend changes to improve the efficacy of the vesting contract regime in managing market power, address any shortcomings and increase the predictability of changes to the vesting contract level (VCL). • Recommend the VCL for the period 1 Jan 2017 to 31 Dec 2018, taking into consideration the outcome of the review.	Section 4
Develop new mechanisms to mitigate market power in the SWEM • Identify possible new mechanisms to mitigate the exercise of market power (including localised market power) by Gencos in the SWEM, either as a substitute for vesting, or to complement vesting. • Recommend and develop the new mechanism(s) to be adopted, based on robust analysis in the Singapore context with the objectives of ensuring market efficiency and equitable market outcomes. • Compare the recommended new mechanisms with the enhanced vesting contracts regime, and assess which or what combination of measures should be adopted.	Sections 5, 6 and 7

2.4 Market participants' comments on the scope of the Review

The three incumbent Gencos provided comments to the EMA with regard to the scope of the Review as summarised in Table 2. All three participants comment on the extent to which the Review should consider the financial viability of existing Gencos. Our evaluation framework for the Review considers the way in which alternative arrangements are likely to affect resource adequacy in the SWEM via incentives for future investments and retirement of generating units (i.e. the economic issue of dynamic efficiency). While not unrelated, we note that resource adequacy and dynamic efficiency are not synonymous with the financial sustainability of the existing Gencos.

Table 2: Market participant comments on the terms of reference

Industry participant comment	Response
YTL PowerSeraya	
• LRMC represents a cap but not a floor, therefore generators recover less than LRMC.	• We discuss this issue in the context of the resource adequacy assessment criterion applied to the current vesting contracts regime (Section 4).
• The Review should consider how vesting contracts could be used to provide incentives to retain an appropriate amount of non-gas-fired plant or be supplemented with capacity payment mechanism to retain an appropriate amount of non-gas-fired plant.	• We discuss the suitability of introducing capacity market for Singapore as an option for managing market power in Section 5
Senoko Energy	
• The Review should consider market sustainability.	• We discuss this issue in the context of the resource adequacy assessment criterion applied to the current vesting contract regime and alternative arrangements (Section 4 and 6).
• The Review should consider implications for FRC.	• We discuss the implications of various options for wider market reform at a high level in Section 7.
Tuas	
• The Review should consider how vesting contracts are allocated between CCGT and steam plant along with the impact of allocation under Vesting Tender.	• We discuss this issue in the context of the review of the current vesting contracts regime and potential changes to it (Sections 4 and 6).
• The Review should consider the merits of implementing a capacity payment mechanism or market.	• We discuss the suitability of introducing capacity market for Singapore in Section 5.

Industry participant comment	Response
• The Review should consider market sustainability.	• We discuss this issue in the context of the resource adequacy assessment criterion applied to the current vesting contract regime and alternative arrangements (Sections 4 and 6).

3 Analytical framework

This Section discusses the analytical framework used for the Review. Section 3.1 discusses participant comments which are relevant to this Section of our draft report. This section then considers the definition of market power (Section 3.2), the relationship between market incentives and the various types of hedging instruments used in the SWEM (Section 3.3), and the evaluation framework used to assess the current vesting contracts regime and alternative mechanisms for managing market power in wholesale electricity markets (Section 3.4). Finally, we present our summary and conclusions (Section 3.5).

3.1 Comments on the draft report

The three incumbent Gencos argue the evaluation framework for the Review should consider the financial sustainability of market participants. Senoko Energy note that the vesting contracts provide Gencos "with a degree of cash flow stability/certainty which is important in an "energy only" electricity market such as Singapore".[4] Senoko Energy suggest a failure to adequately remunerate existing capacity will mean investment decisions "will need to reflect a perceived increase in regulatory risk".[5] Tuas Power argue the Review "should take into consideration the contribution of the generation companies in providing a reliable and secure source of power to Singapore".[6] YTL PowerSeraya argue the Review does not adequately assess resource adequacy, given short-term focus of the modelling informing the Review, the long-term perspective of investment and the perception that the current vesting regime is unfair.[7]

In response, the EMA clearly states that the vesting contracts are not intended to provide revenue certainty for businesses or support the commercial decisions of businesses operating in the SWEM. The evaluation framework presented in Section 3.4 therefore does not consider the financial impact of the vesting regime on existing market participants. Rather, it assesses the impact of vesting regime on, *inter alia*, the likely future resource adequacy of the electricity industry, based on the extent to which it promotes efficient investment and retirement decisions

4 Submission from Senoko Energy, June 2016, p1.

5 Submission from Senoko Energy, June 2016, p3.

6 Submission from TuasPower, June 2016, p4.

7 Submission from YTL PowerSeraya, June 2016, p1-4.

in the longer run, and transparency and predictability for both existing and potential future market participants.

No comments were received regarding this section in the revised report.

3.2 Market power and its mitigation

Before embarking on an examination of tools to mitigate market power, it is important to clarify what is meant by market power and why market power is of concern to policy-makers and regulators. In the purest sense, market power can be described as "the ability [of sellers] to alter profitably prices away from competitive levels", no matter how fleeting or minimal.[8] However, real-world markets rarely replicate the stylised economic model of perfect competition, and therefore most markets reflect the potential for sellers to exercise market power to some degree.

Policy-makers and regulators for wholesale electricity markets often adopt looser definitions of market power in order to differentiate between more and less extreme departures from perfect competition. Such differentiation helps to distinguish between markets in which regulatory intervention may be justified and markets in which the costs of intervention may outweigh the benefits. For example, the Australian Energy Market Commission (AEMC) makes a temporal distinction between generators having 'transient pricing power', or a transient ability to increase prices for short periods of time, and 'substantial market power', or sustained pricing above the level that would prevail in a workably competitive market.[9] As we discuss in Section 5, policy-makers and regulators in different jurisdictions have adopted different tolerances for the temporal extent of market power, reflecting local market conditions and perspectives.

As well as having a temporal dimension, market power can have a geographic dimension. One approach is to focus on a Genco's ability to raise prices across the entire span of the SWEM. However, this approach overlooks the potential for Gencos to exercise market power across smaller geographic subsets (or regions) of the SWEM when transmission lines become constrained. At these times, Gencos with generating units located in an importing region may be required to run to meet demand in that or other region(s). When this happens,

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8 Mas-Collel, A., A. Whinston and J. Green (1995), *Microeconomic Theory*, New York, Oxford University Press, p.383; Stoft, S. (2002),., *Power System Economics, Designing Markets for Electricity*, IEEE Press, p.317.

9 AEMC, *Final Rule Determination, Potential Generator Market Power in the NEM*, 26 April 2013, p.19.

importing region Gencos can have a significant ability to profitably raise prices at a particular node. The scope for Gencos to exercise localised market power depends on the power transfer capability of the network, the sizes, locations, technologies and costs of generators within that network, and the sizes, locations, and consumption profiles of loads across the network. Our Review includes the development of mechanisms that, *inter alia*, address the potential for *localised* market power in the SWEM.

Market power raises concerns for policy-makers and regulators because it can compromise economic efficiency and transfer wealth from consumers to producers. Measures to prevent or deter generators from exercising market power can provide immediate benefits to consumers, as well as promote more efficient electricity consumption and production decisions in both the short and the long run. However, measures preventing the exercise of market power can – in the context of other features of a market design – make it more difficult for generators to earn sufficient revenues to recover their fixed and sunk costs. Policy-makers and regulators therefore need to consider a range of trade-offs when evaluating measures to mitigate generator market power. Section 3.4 presents a framework informing the assessment of alternative market power mitigation measures presented in this report.

3.3 Wholesale hedging and market power

The incentives of a generator to exercise market power in an energy-only wholesale market in large part depend on the relationship between spot prices and the generator's profits. The stronger the positive relationship between spot prices and the generator's profits, the greater the generator's 'long' exposure to spot prices and the greater its incentives to engage in *physical* or *economic* withholding of its generation capacity. Physical withholding refers to the generator making its capacity unavailable to the market. Economic withholding refers to the generator only offering its capacity to the market at prices well in excess of its opportunity cost of generation, also known as its avoidable cost or short run marginal cost (SRMC).

Other things being equal, to the extent a generator's long exposure to the spot prices is offset (or 'hedged') in some manner, the generator's incentives to engage in withholding strategies will be smaller. A generator's long position may be hedged either *physically* or *financially*.

A generator that also serves retail customers – either itself or through a related retailing business – can be described as having a physical or '*natural*' hedge against its long position. Such a generator (or 'gentailer') will have smaller incentives to withhold output than if the generator did not have that retail position. A Genco with a given generation capacity and an equal retail load position would be indifferent, at least in the short term, to the spot prices.

Similarly, a generator that is the selling counterparty under a swap contract can be described as financially hedged, because its obligations under the contract reduce the extent to which it benefits from higher spot prices. For example, if a Genco with 1,000 MW capacity had sold 1,000 MW of market CfDs, its exposure to the spot prices would be fully financially hedged for the duration of those CfDs.

Generators whose long positions are fully physically or financially hedged have little to gain in the short run by withholding contracted capacity when the spot prices exceed their SRMC. With regard to incentives to exert market power, the key nature of hedges is the type of hedge, the extent to which volumes under the contract are firm and the nature of settlement.

In the SWEM, there are a number of mechanisms that act to hedge generation capacity:

- **Vesting contracts and tenders for unvested MSSL load**[10] are firm swap contracts for an agreed volume of energy at an agreed price that settle on a half hourly basis. Settlement for these contracts is relative to the Genco's weighted average nodal spot prices. In the case of allocated vesting contracts, contract volumes and prices are imposed, whereas tendered contracts are entered into voluntarily at volumes and prices offered by Gencos.
- **Other bilateral contracts** are regularly struck between Gencos, typically to manage planned outage events or other short term exposures. Such contracts, representing bilaterally negotiated arrangements, contain a range of durations and settlement terms but are usually firm swap contracts that settle on a half hourly basis against USEP.
- **SGX Futures** are exchange-traded futures contracts. Such contracts are essentially anonymous (as the exchange is the counterparty to all contracts), with trade occurring more frequently and at publically visible prices. Currently SGX only offers a flat swap product that settles against USEP on an average quarterly basis.
- **Retail customers** provide a hedge for a vertically integrated businesses in a manner similar to a wholesale contractual position, and are sometimes referred to as a natural hedge.[11] Retail load is not always known exactly in

10 See Figure 1 and section 4.1.1 for a more complete description the various MSSL contracts in the SWEM.

11 Whilst there may be various internal contracting arrangements between the generation and retail arms of a vertically integrated business, from the perspective of the overall business there is an

advance (due to uncertainty around demand) making a retail hedge non-firm. Retail customers also 'settle' on an average basis aligned with customer billing and recontracting cycles.

Each of the hedging mechanisms above can be considered close (but not perfect) substitutes with regard to incentives to exert market power. For a given volume of hedges, firm swap contracts that settle on a half hourly basis are likely to exert a stronger mitigating effect on incentives to exercise market power than hedges that settle in an averaged manner over longer timeframes.

3.4 Evaluation framework

The SWEM objectives highlight the importance of economic goals such as efficiency, competition and non-discrimination, along with technical considerations including safety and reliability.[12] It is therefore important that market power mitigation measures are assessed against a range of criteria that reflect those objectives. Accordingly, we have evaluated the current vesting contract regime and alternative market power mitigation measures against the following criteria:

- **Effectiveness:** the likely effectiveness of the measure in mitigating the exercise of market power, at both a market-wide and localised geographic level.
- **Dispatch efficiency:** the extent to which the measure could promote or undermine least-cost dispatch of generation to meet demand. Measures which minimise the resource costs of serving demand are preferred over those that could result in out-of-merit order dispatch.
- **Resource adequacy:** the influence of a measure on incentives for capacity investment and retirement decisions with the aim of meeting desired reserve levels and reliability standards efficiently (also known as 'dynamic efficiency').[13] Market power mitigation measures may need to be coupled with

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ability to 'look through' these internal arrangements in terms of overall strategy. This is fundamentally different to wholesale contracts with external parties.

12 Singapore Electricity Market Rules, Chapter 1, Section 3.1.

13 We note that ensuring dynamic efficiency is not synonymous with ensuring the financial sustainability of all incumbent participants at all times. For example, under conditions of oversupply dynamic efficiency is achieved by the exit of suppliers that are not economically (and therefore not financially) viable.

other changes to ensure overall incentives are appropriate for achieving dynamic efficiency.

- **Intrusiveness and administrative burden:** the onerousness and cost for participants to comply with the measure, and for the EMA to monitor and enforce compliance with the measure. Other things being equal, less intrusive and onerous measures are preferable, as they are likely to result in lower implementation and ongoing costs.
- **Transparency and predictability:** the extent to which the measure operates in a manner that existing and prospective participants can reasonably anticipate. This should promote investment and participation in, and the competitiveness of, the wholesale and retail markets.

As noted in Section 3.1, there are typically trade-offs and linkages between these types of objectives. A particular option may be extremely effective in mitigating the exercise of transient market power, but by constraining the ability of generators to recover their fixed costs, it may compromise resource adequacy and deter competitive entry. Conversely, a measure that operates transparently and predictably may enhance the prospects of preserving resource adequacy.

The following sections of this report systematically apply this evaluation framework, drawing on qualitative and quantitative analysis, to assess the existing vesting contracts regime and potential new market power mitigation measures. This systematic approach ensures the relative pros and cons of the alternatives, including any resulting trade-offs, are recognised.

3.5 Summary and conclusions

Market power is concerned with the incentives and ability of generators to move prices away from competitive market levels. In the electricity market, policy-makers tend to be concerned about sustained pricing above the level that would prevail in a workably competitive market. This Review is concerned with market power that arises on a localised (nodal and regional) basis, as well as market power that can be exerted across the SWEM.

The existing regime and alternative mechanisms to mitigate market power considered in this report are systematically evaluated, drawing on qualitative and quantitative analysis, against a common set of assessment criteria:

- effectiveness
- dispatch efficiency
- resource adequacy
- intrusiveness and administrative burden
- transparency and predictability.

4 Review of the existing vesting contracts regime and recommended VCL for 2017-18

This Section reviews the efficacy of the existing vesting contracts regime, and recommends the VCL for 2017-18. It is divided into several key parts:

- Section 4.1 discusses the comments relevant to this Section of our draft report.
- Section 4.2 describes the key features of the existing vesting contracts regime.
- Section 4.4 briefly outlines other market power mitigation measures operating in the SWEM.
- Section 4.5 describes our assessment of the appropriate VCL for 2017-18 and sets out our recommended adjustments to the VCL, based on the requirements contained in the EMA Procedures.
- Section 4.6 assesses both the past and likely future performance of the vesting contracts regime, assuming that the VCL for 2017-18 is adjusted along the lines we recommend.
- Section 4.7 suggests some minor enhancements to the existing vesting contracts regime that we consider should be implemented assuming the vesting contracts regime is to remain in place in some form.
- Finally, section 4.8 sets out our summary and conclusions.

4.1 Comments on the draft report

Many submissions comment on the existing vesting contract regime, and in particular the proposed VCL for 2017 and 2018, the approach to adjusting the VCL over time and the requirement to hedge unvested MSSL load. We outline and then address the comments made on each of these issues in turn.

4.1.1 The proposed VCL for 2017 and 2018

Senoko Energy, Tuas Power and YTL PowerSeraya comment that reducing the VCL in line with the recommendations of the draft report would threaten the financial viability of market participants. They recommend increasing the VCL to 40%, rather than reducing the VCL, to ensure the financial viability of existing generation businesses. The three incumbent Gencos argue the vesting contract regime effectively caps prices, limiting the ability of the generators to recover fixed costs. Senoko Energy argue for the adequate remuneration of effective capacity, which could be achieved via the vesting contracts or an alternative scheme, would require a VCL of around 40%.[14] Tuas Power suggest "a VCL of 40 percent for 2017-2018 should be set on the basis of market sustainability", after which time it could be reduced to reflect reductions in contracted gas demand.[15] YTL PowerSeraya suggest that the EMA increase VCL to 40% until 2023 to "provide a workable minimum degree of revenue support for generators".[16] Senoko further suggest that our comparison of spot electricity prices should include an "adjustment for the fact that vesting prices are set on a forward basis while pool prices reflect "spot" conditions",[17] potentially altering our conclusions regarding the impact of the vesting regime on resource adequacy.

Other participants were supportive of reducing the VCL, with Tuaspring, Keppel, SembCorp Cogen, PacificLight Power and RCMA supporting a reduction in the VCL. SembCorp Cogen argue the VCL "should be reduced to LNG vesting level starting 1 January 2017", since retaining the vesting regime would support an unnecessary and "intrusive market measure that adds inefficiency to the market".[18] RCMA agrees that the removal of the current burden and lack of transparency associated with removing vesting contracts "would be a positive aspect for the market and result in cheaper electricity costs for consumers".[19]

In response, we acknowledge the Review takes place in the context of challenging market conditions for generation businesses. Wholesale electricity prices in the SWEM are below historical averages and well below LRMC, reflecting the supply-demand balance and large volume of gas available in the market. However, the Review is focused on the mitigation of market power, rather than the provision of financial support to generators. Our analysis demonstrates the vesting contract regime does not appear to have capped market prices in practice, as demonstrated by Figure 2 and discussion in Section 4.6.3.

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14 Submission from Senoko Energy, pp3-4.

15 Submission from Tuas Power, p4.

16 Submission from YTL PowerSeraya, p2, 8.

17 Submission from Senoko Energy, p3.

18 Submission from SembCorp Cogen, p2-3.

19 Submission from RCMA, p1.

In response to Senoko's comments regarding adjustment of the vesting price to reflect spot conditions (Figure 2) we would note a number of points. Firstly, the vesting contract price, whilst set periodically on a forward looking basis, is set quarterly. This ensures there is only limited scope for divergence between *ex ante* estimated vesting prices (specifically the energy component) and actual electricity spot price outcomes, as opposed to a vesting price that is updated less frequently. Second, divergences between *ex ante* estimates of fuel prices and actual electricity spot price outcomes could arise from a number of factors, including unexpected supply-demand conditions in the market, transmission outages or unexpected shocks to input costs. There is no reason to expect that the forward looking vesting price would be systematically biased as it is based on futures prices. This means any spot adjusted LRMC estimate could be either above or below a forward looking estimate like the vesting price at any point in time. Finally, the Gencos source the majority of their fuel via long term gas supply agreements that are priced in a manner broadly analogous to the approach used to set the vesting price itself, as opposed to making spot purchases for any significant proportion of their demand for gas. Whilst we agree that generators should be continuously marking their position to market, that does not mean that short term fluctuations in spot fuel prices would prevent the Gencos from benefitting when spot electricity prices rise above the forward looking VCP estimate of LRMC.

Our quantitative and qualitative analysis demonstrates a reduction in the VCL is achievable, subject to unvested MSSL load remaining hedged. The removal of vesting contracts improves transparency and is likely to increase dynamic efficiency (via changed incentives around uneconomic steam units) and should therefore promote, rather than hinder, resource adequacy in the medium to long term.

4.1.2 The proposed transition path for adjusting the VCL

There is some divergence of opinion regarding the optimal transition path for adjusting VCL over time. In particular, some participants suggest a gradual adjustment in the VCL while other participants recommended a step change to the recommended vesting levels for 2017 and 2018, and then to LNG vesting. As noted above, SembCorp Cogen comment the VCL should be reduced to LNG vesting level from 1 January 2017. Similarly, YTL PowerSeraya argue that reducing the balance vesting quantity to zero over a two to three year period would be "an unwelcome degree of micro- adjustment by the regulator, which is neither justified by an analysis of market power, nor the need for any transitionary support".[20] In contrast, PacificLight Power support a gradual reduction in the VCL at a pre-determined rate to "ensure that the market is not subject to sudden changes that could adversely impact market equilibrium".[21]

In relation to the proposed transition arrangements, we believe that a gradual approach is preferable. Large step changes in aggregate contract positions have the potential to be disruptive. Moreover, care should be taken to ensure appropriate enabling arrangements are in place to facilitate the transition, including the requirement to prudently hedge unvested MSSL load.

In view of the industry's feedback, we therefore recommend a gradual roll down of the VCL over two to three years, to ensure market participants have adequate time to adjust their trading positions. This recommendation is conditional on the unvested MSSL load being hedged as discussed in Sections 4.5.3, 4.7 and 7.3.

4.1.3 The requirement to hedge MSSL load

YTL PowerSeraya comment that assessing the market power of generators based on the way in which MSSL procures power is a new approach, which effectively "move[s] the goal posts".[22]

In response, we note that this Review is the first VCL review that starts with a VCL less than the MSSL load. Our recommendation is not to set the VCL based on the way which MSSL procures power, but rather to ensure that any unvested MSSL load arising from the reduction in VCL is hedged, consistent with the expected behaviour of a retailer exposed to wholesale purchasing risk in a market like the SWEM. Our modelling analysis suggests market outcomes under various VCLs do vary for different levels of assumed spot exposure across Gencos and the MSSL (i.e. whether the unvested MSSL load is hedged or not). Consideration of varying levels of spot exposure has been a feature of previous reviews.

Hedging the unvested MSSL load will minimise any risk to competitive and efficient market outcomes associated with the VCL reduction. Our recommendation on the VCL is therefore conditional on the hedging of unvested MSSL load.

Several participants made more specific comments about the approach to hedging unvested MSSL load, which are discussed in Section 6.1.

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20 Submission from YTL PowerSeraya, p8.

21 Submission from PacificLight Power, p1.

22 Submission from YTL PowerSeraya, p4.

4.1.4 Modelling and analysis

Several participants made comments on the modelling that informed the analysis in this section of the report. Tuas Power, Senoko Energy and PacificLight Power express concern that the modelling may need to be revised to reflect the adjustment to the LRMC estimation reflected in the addendum to our report. In response, we note our modelling analysis assumed a confidential input fuel price provided by the EMA. This fuel price was used to calculate short run marginal costs (SRMCs) and the resulting modelled market outcomes. We calculated LRMC as a comparator to benchmark against the modelled results. Our original LRMC used a fuel price as of 2014, which was subsequently corrected in the addendum. However, a difference remains between the confidential fuel price used to calculate SRMC that drives the modelled results, and the fuel price used to calculate the comparative LRMC. This difference, which is illustrated in Figure 17, arises due to our modelling assuming a 'pure' pipeline gas cost whereas our LRMC calculation uses the blended pipeline gas and LNG cost as per the VCP calculations.

Our recommendation on VCL is conditional on prudently hedging the unvested MSSL load. With the unvested MSSL load prudently hedged, our modelling forecasts pool prices around $70/MWh for the base case and less than $100/MWh for the sensitivity cases. These forecasts are substantially less than either the original or updated comparative LRMC, and indeed are less than any LRMC that assumed the same fuel price as the modelling (which remain significantly above $100/MWh. Our conclusions and recommendations therefore remain unchanged. We further note that changing the assumed input fuel cost in our modelling would act to lift the level of prices in all cases and for all modelled VCL values, but would not materially impact on the relativities between cases. Our recommendations are based on the relative differences between assumed vesting contract levels and the various market power mechanisms.

Tuas Power and Senoko Energy comment that the modelling analysis systematically understates the potential for Gencos to exercise market power. In particular, they highlight the likely retirement of steam plant following the removal of VCL, the calibration of modelled prices for 2015 compared to actual 2015 average USEP, the limited number of demand points modelled which understates volatility, and the exclusion of contingency reserve from the modelling analysis. In response, we note the points raised do not suggest we have systematically underestimated market power. In particular:

- The modelling analysis is based on reasonable assumptions, developed in discussion with the EMA, and the modelling results are robust to a range of sensitivities.
- We have undertaken a supply-demand sensitivity, which assumes around half the steam plans is retired from the market and that demand growth is higher

than currently expected, as discussed in Appendix C – Market modelling inputs.

- On the issue of calibration, Appendix D – Market modelling calibration results identifies that we did not include a number of constraints that occurred in practice during 2015, and that this explains much of the difference between modelled and actual prices in 2015.
- The demand points modelled were determined based on robust statistical sampling techniques, to ensure variation in demand is captured. This allows us to model a large strategy set and focus the analysis on participant incentives. We have modelled 3,936,600 unique bidding combinations per annum across 150 unique levels of demand, substantially more than the 17,520 trading intervals per year.
- Contingency reserve has been excluded from the analysis, consistent with our demand point modelling methodology. We expect that the inclusion of contingency would raise prices by a small amount in each case, but would be unlikely to lead to a materially increase in the relativities between cases (for example between VCL 25% and 20% cases which both include contingency reserves).

Accordingly, there is no evidence to suggest the modelling analysis underestimates the extent of market power in the SWEM.

Senoko Energy request additional information about a series of modelling assumptions and results. Additional information has been included in Appendix C – Market modelling inputs and Appendix E – Quantitative analysis results.

YTL PowerSeraya comment that the impact of Status Quo is unclear without a clear statement of the implied vesting levels for 2017/18 under this method".[23] In response, we note that we modelled a range of VCLs (35%/30%/25%/20%/LNG level) as set out in Section 4.5.2. Our recommendation that there is scope to reduce VCL under the status quo to LNG vesting is based on this analysis.

4.2 Comments on the revised report

Many participants commented on the VCL following the publication of the revised report, further to the comments made on the draft report (Section 4.1.1). YTL PowerSeraya suggests the VCL should be set at a minimum of 40% up to

23 Submission from YTL PowerSeraya, p5.

2023. PowerSeraya suggests this review determine the VCL for 2017-18 and an indicative VCL for 2019-20 which could be revised in a review to take place in 2018. Similarly, Senoko comments the VCL should be set in excess of 25% to mitigate the issues associated with financial viability. In response, we note our analysis of market power in the SWEM suggests there is no market power in the near term and there is scope to gradually reduce vesting to LNG vesting levels, along with prudent hedging of the unvested MSSL load.

In response we note Keppel Merlimau Cogen (Keppel) and PacificLight Power (PLP) comment that since vesting contracts are not required to manage market power, and the rollback to LNG vesting is meant to be transitory, a more rapid roll down schedule should be adopted. Similarly, Tuaspring comments that the proposed VCL rollback schedule is inconsistent with EMA's September 2014 decision and the Frontier Economics' recommendations and the VCL should be reduced to LNG vesting level from 2017.

Frontier Economics suggests a gradual rollback of 2 to 3 years to minimise market disruption and enable trading arrangements and capability to be developed, which is not inconsistent with the EMA's recommendations.

4.3 The existing vesting contracts regime

This section provides a broad overview of the vesting contracts regime as it currently stands. We briefly discuss the historical context of the regime before turning to details of the counterparties, contract classes, type, price and volume.

4.3.1 Context

Vesting contracts have been used across a number of jurisdictions, particularly in the early stages of wholesale market liberalisation.[24] Vesting contracts in the SWEM were imposed at the start of the market and have remained a feature of the wider regulatory regime since that time.

In most cases, the reason for introducing vesting contracts arises from a combination of two reasons. The first reason is to provide revenue certainty to both generators and retailers, particularly during the early years of wholesale

24 For example, vesting contract arrangements were widely used at the commencement of the UK and Australian electricity markets.

market liberalisation.[25] The second reason is to manage any perceived or actual market power issues.

In Singapore's case, vesting contracts were introduced to assist with the management of any market power issues in the SWEM. In recent years, spot prices for electricity have been consistently below vesting contract prices, to some extent complicating the perceived objective of the regime as Gencos' returns are currently supported by the vesting to some extent.

Our Review focuses on the features of the current vesting contracts regime based on its effectiveness at managing market power in the SWEM.

4.3.2 Counterparties

The current vesting contracts are imposed between:

- each of the Gencos that were operating or planned at the commencement of the SWEM (i.e. Senoko Energy, YTL PowerSeraya, Tuas Power Generation, Sembcorp Cogen, Keppel Merlimau Cogen and PacificLight Power) and
- the MSSL, SPS.

As the MSSL in the SWEM, SPS provides market support services such as meter reading and data management, and facilitate customer transfers between retailers. In addition, SPS has responsibility as the retailer of last resort to serve non-contestable customers (NCCs, i.e. customers who choose to remain with or are permitted to revert back to SPS to buy at the regulated tariff), and facilitate access to the wholesale market for retailers and contestable customers. Following the commencement of full retail competition in electricity (FRC), SPS will retain its role as the retailer of last resort. For simplicity, this report will refer to the load of currently non-contestable customers supplied by the MSSL as the 'MSSL load'. This includes customers that are currently non-contestable as well as those customers who, post-FRC, continue to be or revert to being supplied at regulated tariff rates by the MSSL.

25 For example, generators in Victoria, Australia, were privatised at a time of excess capacity in the Australian NEM. Vesting contracts were imposed for five years at strike prices well above the expected competitive wholesale price to underwrite the sale values of those generators. See Booth, R.R, *Warring Tribes, The Story of Power Development in Australia*, Revised Edition (2003) Published by The Bardak Group, p.64. Vesting strike prices were set at A$38.50/MWh whereas average spot prices averaged approximately half that amount.

4.3.3 Contract classes

Contracts with the MSSL as counterparty fall within one of the following classes:

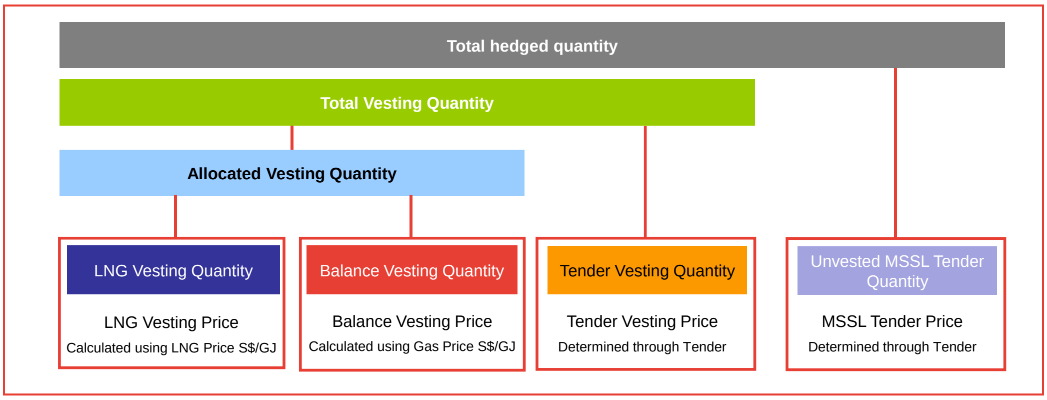
- Allocated Vesting Quantities – comprising:
  - LNG Vesting Quantities
  - Balance Vesting Quantities and
- Tender Vesting Quantities
- Unvested MSSL Tender Quantity (which are not directly part of the vesting contracts regime but are related to it).

The Total Vesting Quantity is determined by the EMA based on forecast electricity consumption to meet the target Vesting Contract Level (VCL).[26] The criteria applied by the EMA to determine the VCL is discussed below.

The Total Vesting Quantity (i.e. the VCL) is achieved through a mix of LNG Vesting Quantities, Balance Vesting Quantities (collectively the Allocated Vesting Quantities) and the Tender Vesting Quantities. To the extent that, over and above the VCL, any (currently) non-contestable MSSL load remains unhedged, then unvested MSSL tenders are employed.

Figure 1 illustrates the relationship between different vesting contracts (including tender vesting contracts) and tenders for unvested MSSL load.

Figure 1: Overview of MSSL counterparty contracts



Source: Frontier Economics

26 EMA Procedures pp.3-12 to 3-13.

LNG Vesting

The EMA introduced LNG vesting contracts in 2013 to encourage Gencos to enter into contracts for regasified LNG to secure future fuel supplies on a commercial basis.[27] LNG vesting contracts comprise flat MW swap contracts.

The LNG vesting scheme is to be in place for ten years and LNG vesting contract holders who qualify for the scheme are allocated a specified amount of LNG vesting quantities, as determined by the EMA.[28] Under the current vesting regime, the LNG vesting level effectively sets the floor for the future level of vesting contracts until the expiry of the LNG vesting contracts in 2023:[29]

> If the Authority decides to rollback the Vesting Contract level, Holders who are allocated LNG Vesting Quantities under the LNG Vesting Scheme shall retain their LNG Vesting Quantities until the termination of the LNG Vesting Scheme regardless of the Vesting Contract level under the rollback schedule.

The volume and pricing of the LNG vesting contracts are not within the scope of this Review.

Balance Vesting

As indicated by its name, the Balance Vesting Quantity refers to the quantity of vesting contracts that need to be allocated to Gencos to 'balance' the difference between the Allocated Vesting Quantity and the LNG Vesting Quantity. Balance Vesting Quantities can only be non-negative.

To the extent that a Genco's Allocated Vesting Quantity is more than its LNG Vesting Quantity, a positive Balance Vesting Quantity will be allocated to that Genco to cover the difference.

Tender Vesting

The Tender Vesting Quantity refers to that portion of the Total Vesting Quantity that the EMA chooses to put to tender, with the objective of introducing competitive pricing to the electricity tariff for NCCs. All Genco holders of existing vesting contracts can participate in the tender, with the prices and

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27 EMA, *Review of the Vesting Contract Level for the Period 1 January 2015 to 31 December 2016, Final Determination Paper*, 22 September 2014, p.A1-8.

28 EMA Procedures, p.1-1.

29 EMA Procedures, p.3-14. See also EMA, *Review of the Vesting Contract Level for the Period 1 January 2015 to 31 December 2016, Final Determination Paper*, 22 September 2014, para 3.2, p.2.

allocation between Gencos for the tendered quantities determined by the outcome of the tender. The quantity of contracts tendered can range between 3 to 12% of electricity consumption.

From 2009 to 2014, the EMA exercised its right to tender a portion of the total vesting quantities.

Unvested MSSL load tenders

Unvested MSSL load tenders have been used in the case where the Total Vesting Quantity (i.e. the VCL) is less than the level of non-contestable load. Similar to the Tender Vesting Quantities, contract volumes and prices are determined on a competitive basis.

4.3.4 Contract type

Vesting contracts are two-way CfDs that hedge a specified amount of electricity (the vesting contract quantity) at a specified price (the vesting contract price), commonly referred to as 'swaps'. Contract counterparties make 'difference payments' to one another when a given Genco's dispatch-weighted average nodal price (Vesting Contract Reference Price (VCRP)[30]) differs from the vesting contract price. Specifically, Gencos make a payment under the vesting contracts if VCRP exceeds the vesting contract price, and receive a payment if VCRP is below the vesting contract price on a half-hour trading period basis. Payments between vesting contract counterparties are settled through the settlement system of the SWEM market operator, the Electricity Market Company (EMC).

4.3.5 Contract prices

The strike price incorporated in all Allocated Vesting Quantities is set to approximate the long run marginal cost (LRMC) of a theoretical new entrant. This LRMC is estimated by considering the most efficient new generation technology in operation in Singapore that contributes at least 25 per cent of the total electricity demand, currently identified as an F-class combined-cycle gas turbine (CCGT).[31]

Different prices are set for LNG Vesting Quantities and Balance Vesting Quantities. The LNG Vesting Price is based on vested LNG prices (in S$/GJ).

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30 See Electricity Market Rules, Chapter 7, clause 3.6 for definition of VCRP.

31 EMA, *Review of the Vesting Contract Price Parameters for the Period 1 Jan 2015 to 31 Dec 2016*, 22 September 2014.

The Balance Vesting Price for each quarter is based on unvested LNG and pipeline gas prices (in S$/GJ) for the quarter.

The Allocated Vesting Price for each quarter to the MSSL is the weighted average of the Balance Vesting Price and the LNG Vesting Price based on the Balance Vesting Quantities and LNG Vesting Quantities to each holder for that quarter. The EMA reviews and sets the vesting price parameters biennially, and recalculates vesting prices quarterly, or as required in accordance with the EMA Procedures.

We note the vesting contract price has been in excess of the prevailing USEP consistently for several years. For example, the Balance Vesting Price for Q1 2016 of S$119.48/MWh[32] compares to an achieved average spot price of S$74.89/MWh (as shown in Figure 2). This implies that any Genco holding vesting contracts is benefitting from a transfer from customers, relative to a counterfactual state of the world in which contract prices are determined using a market-based approach (such as tendering).

This Review does not consider changes to the pricing of vesting contracts.

4.3.6 VCL

The overall proportion of total electricity consumption hedged under vesting contracts is referred to as the vesting contract level (VCL). Under the current vesting contracts regime, the VCL is reviewed biennially.

The VCL is set primarily to curb the market power of the Gencos "to an acceptable level" and to encourage the spot market price "not to average above LRMC".[33] The EMA Procedures provide that the EMA:[34]

> …will use an analytical model, preferably a market gaming model, to derive the overall expected annual market prices for different contract levels (as a percentage of annual load). These will be derived from the weighted average expected annual market prices for each period type. More specifically, the Authority will use the model to simulate non-collusive interactions amongst the Gencos and determine the Vesting Contract level to effectively control the Gencos' market power. Specifically, the model estimates the Vesting Contract level required to remove the Gencos' incentives to withhold capacity to raise the spot prices in the wholesale electricity

32 See https://www.mypower.com.sg/About/Vesting_Contracts/Vesting_Data.html for final vesting prices by quarter.

33 EMA, *Introduction to the National Electricity Market of Singapore*, Version 6, Updated as of October 2010, section 8.1, p.8-1. See footnote 1.

34 EMA Procedures, p.3-13.

> market above a certain target price. The Vesting Contract level is set to target the long run marginal cost ("LRMC") of a theoretical new entrant… This mimics the outcome of a competitive market over the long-run and ensures appropriate price signals remain for investors to plant new and efficient generation capacity to meet demand growth.

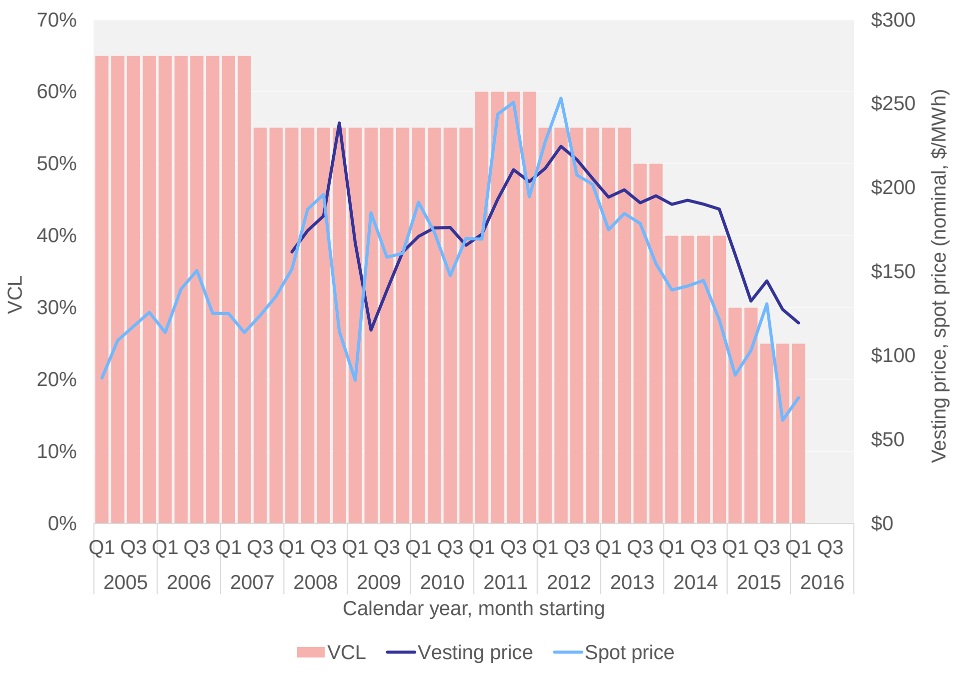
Under the EMA Procedures, the following factors are taken into account in setting the VCL and balanced at the discretion of the EMA:[35]

- The expected LRMC of a theoretical new entrant, as calculated for the vesting price.
- Supply and demand projections at the point of review.
- The robustness of different contract levels to data uncertainty.
- The likely data scenarios, including the range of plant configurations that may exist.
- The transition away from vesting contracts should occur via a monotonic rollback schedule, if possible, thereby avoiding frequent fluctuations in the VCL.

Figure 2 shows vesting contract levels and prices over the period since they were introduced. The initial vesting contract level was set at 65% of electricity demand, and has reduced since the first quarter of 2012 to the present level of 25%.

35 Section 3.4.1, pp.3-13 to 3-14.

Figure 2: Vesting contract levels and prices (quarterly, Q1 2005 – Q4 2016)



Source: Frontier Economics

4.3.7 Sculpting of vesting contracts

While the VCL is stated as a single percentage number, it is sculpted to represent a progressively larger proportion of forecast total demand during off-peak times, shoulder times and peak times.

The MSSL is obliged on behalf of the EMA to divide the week into three representative day-types:[36]

- Sundays and public holidays
- Saturdays
- All other days (i.e. working weekdays).

The MSSL must then allocate each half-hour across the three day-types into one of three period-types, each of which is to include one-third of half-hours:[37]

36 EMA Procedures, p.3-11.

37 EMA Procedures, p.3-11.

- Peak period will be the 1/3rd of half-hours with the highest average electricity consumption for all day-types
- Off peak period will be the 1/3rd of half-hours with the lowest average electricity consumption for all day-types and
- Shoulder period will be the remaining 1/3rd of half-hours for all day-types.

Taking the shoulder period as the numeraire, the MSSL is then required to apply a 'peak weighting factor' of greater than one to peak periods, such that the peak contract level is greater than the shoulder contract level. The weighting factor applied to off-peak periods is less than one, set such that the period load-weighted contract level equals the average contract level. This implies that the off-peak contract level is less than the shoulder contract level. The objective of sculpting is to:[38]

> …bring the market power in the peak period to within an acceptable range of that in the shoulder period… A weighting factor will be chosen to achieve similar expected prices across the three period types.

However:

> Since it may not be possible to achieve exactly equal prices from the model, and given the uncertainty of future data assumed in the model, the Authority will use its discretion to choose a peak period weighting factor that will approximately achieve these objectives.

4.3.8 Allocation of vesting contracts

The VCL for a given period is allocated between the vested Gencos based on their individual share of the sum of their historically licensed or planned generation capacities at the commencement of the vesting contracts regime.[39] The EMA will adjust the allocation to take account of Gencos' planned and notified changes to their installed capacity, due to either retirement or planned outages.[40] The EMA will also exclude installed generation capacity that is unavailable for a period of more than six consecutive months overlapping with the relevant quarter.

38 EMA Procedures, p.3-15.

39 The Genco capacities used to allocate vesting contract quantities are as follows (all in MW): Senoko Energy (3300) , Power Seraya (3100), Tuas Power Generation (2546.9), Sembcorp Cogen (785), Keppel Merlimau Cogen (470) and PacificLight (800) (Total: 11001.9 MW). Note that these capacities are in some cases less than recent actual (end 2015) registered generation capacities.

40 EMA Procedures, p.3-12.

4.4 Other market power mitigation mechanisms

In addition to the vesting contracts a number of other mechanisms in the SWEM act to militate against the exercise of market power by the incumbent Gencos. This section provides a brief overview of those mechanisms.

4.4.1 Price cap

The nodal prices paid to generators in the SWEM are capped at S$4,500/MWh. This cap has been set to represent 90% of the Value of Lost Load (VoLL), or cost to customers of unmet demand, determined as S$5,000/MWh for Singapore.

4.4.2 Capacity caps

The three incumbent Gencos currently face caps on their licensed capacities. These limits are 3,330MW for Senoko, 3,100MW for YTL PowerSeraya and 2,670 for Tuas. As at the end of December 2015, the licensed capacities for Senoko and YTL PowerSeraya were at these limits, and Tuas was only 93.1MW short of its limit.

As a result of the capacity caps and recent investments in generation facilities by other participants, the market shares of the largest three Gencos have been declining.

4.4.3 Market monitoring

The EMA is obliged under section 3 of the *Electricity Act* to, *inter alia*:

- Protect the interests of consumers with regard to prices, reliability and quality of services.
- Ensure security of supply of electricity to consumers and to arrange for the secure operation of the transmission system.
- Create an economic and regulatory framework for the electricity sector that promotes competitive, fair and efficient market conduct and prevents the misuse of monopoly or market power.

In line with these requirements, the EMA undertakes continuous monitoring of market outcomes and has the discretion to undertake investigations or formal inquiries.

4.4.4 Others

The EMA is empowered, under the *Electricity Act*, to examine, *inter alia*, conduct that may constitute an abuse of a dominant position. Section 51 of the *Electricity Act* provides that:

> Any conduct on the part of one or more persons which amounts to the abuse of a dominant position in any wholesale electricity market or the retail electricity market in Singapore is prohibited if it may affect trade within Singapore.

Further, conduct may constitute abuse if it consists of, *inter alia*:

> (a) Limiting generation of electricity, any wholesale electricity market, the retail electricity market or technical development in the electricity industry in Singapore to the prejudice of consumers;

In addition, section 50 of the Act proscribes:

> …agreements, decisions or concerted actions which have as their object or effect the prevention, restriction or distortion of competition in any wholesale electricity market in Singapore.

These powers under the Act constitute a powerful avenue to respond in the event that the EMA perceives an abuse of market power.

4.5 Review of VCL for 2017-18

The EMA requested Frontier Economics to undertake a review of the VCL for the calendar years 2017 and 2018, in accordance with the requirements in the existing EMA Procedures. This section discusses how we performed the review and explains our draft recommendations.

4.5.1 Review criteria

As noted in section 4.1, the VCL must be reviewed biennially under the current vesting regime. The EMA Procedures state that:[41]

> To achieve the objective of effectively curbing the potential exercise of market power by the Gencos, the Authority will, in consultation with the industry, review and reset the Vesting Contract level every two years based on supply and demand projections at the point of review. While the long-term plan is to reduce the Vesting Contract level over time, such reduction is contingent on the dilution of Gencos' market power in the generation market.

Section 4.1 also notes that the EMA Procedures require a number of factors to be taken into account in setting the VCL. To reiterate, these are:[42]

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41 p.3-13.

42 pp.3-13 to 3-14.

- Achieving annual average price outcomes that reflect the expected LRMC of a theoretical new entrant, as calculated for the vesting price.
- Supply and demand projections at the point of review.
- The robustness of different contract levels to data uncertainty.
- The likely data scenarios, including the range of plant configurations that may exist.
- The transition away from vesting contracts should occur via a monotonic (unreversed) rollback schedule, if possible, thereby avoiding of frequent fluctuations in the VCL.

The EMA has discretion as to how it balances these factors, subject to the key regulatory objective of effectively curbing the potential exercise of market power by the Gencos.

The EMA Procedures state that the EMA will utilise an analytical model – preferably a gaming model – to derive annual market prices for different VCLs. Such prices are to be derived from the weighted average expected annual market prices for each period type (peak, shoulder and off-peak). The analytical model is to be used to simulate *non-collusive interactions* amongst the Gencos with a view to setting the VCL in such a way as effectively controls the Gencos' market power.[43] The reference to the need to model 'non-collusive interactions' is significant in our view, as discussed below in the context of our modelling methodology.

4.5.2 Frontier's approach to the review

Options modelled

We modelled a wide range of potential VCLs for 2017-18 – these being:

- 35%
- 30%
- 25%
- 20%
- LNG vesting level.

43 EMA Procedures, p.3-13.

Our modelling and assessment also incorporated the option of the EMA tendering to the market for the difference between the expected MSSL load and the relevant VCL. For example, with an MSSL load of 29% and a potential VCL of 20% (for a given period and day type), the 'unvested NCC' load and therefore the proportion of total consumption tendered by the EMA would be up to 9%. Volumes so tendered would be fixed swap volumes of a similar form to the existing vesting contracts with the same day-type and period-type sculpting, and strike prices determined via the tender. The EMA would accept tenders from Gencos in ascending order of tendered strike price until the requirement was fulfilled. We modelled the different VCLs both with and without the unvested MSSL load being hedged in this manner.

We note that allocated vesting contracts and tendered contracts are close substitutes but differ in two ways.

First, the shape of the contract, by time (peak/shoulder/off-peak) and by day-type, will differ. MSSL load contracts are shaped to match MSSL load unlike vesting contracts which are higher during peak times and lower during off-peak times.

Second, the allocation to specific Gencos will differ. Allocated Vesting Quantities are allocated to vested Gencos based on the EMA Procedures whereas tendered contract quantities are allocated according to the market-based outcomes of the tender.

These differences make vesting and MSSL tender contracts close, but not perfect, substitutes for each other in terms of market power mitigation. The same argument applies to hedging unvested NCC load via the SGX. Which form of contract is more effective at mitigating market power is an empirical question that we seek to address in our analysis below.

Scenarios and sensitivities considered

The scope of analysis included the following:

- A base case scenario, which involved the measurement of price distribution effects when increasing or decreasing the VCL from the current VCL of 25%.
- A bidding sensitivity, where we assumed that both steam and OCGT units were offered into the market at $350/MWh, which is roughly equivalent to

an OCGT unit with double fuel costs (and higher than the current SRMC of any plant in the market).

- A supply-demand sensitivity, where we tightened supply-demand conditions by assuming that:
  - the growth rate for energy/peak demand is doubled and
  - around half of the steam units are removed from the market.[44]

The above cases have been modelled using a stochastic treatment of generator forced outages. This approach is discussed in more detail in Appendix C – Market modelling inputs.

Modelling methodology

We utilised our strategic bidding and dispatch model, *SPARK*, to compare potential SWEM outcomes given different VCLs and whether or not unvested MSSL load is hedged.

SPARK is a plant dispatch model that utilises game theory to identify sets of generator bidding strategies that yield Nash Equilibria. A Nash Equilibrium is a set of strategies where no party (in this case, no Genco) has an incentive to unilaterally deviate from its strategy. Put another way, a Nash Equilibrium is a situation where given the strategies adopted by other parties, no single party acting on its own can increase its payoff by changing its strategy. This does not imply that a Nash Equilibrium will represent an optimum set of strategies for the parties concerned, or that the parties' strategies will naturally tend towards Nash Equilibria outcomes. Rather, a Nash Equilibrium simply means that the set of strategies in question is *stable*, in that there are no endogenous forces that will encourage the relevant parties to shift away from their strategies.

Depending on the number of generators modelled as strategic players, *SPARK* will often identify multiple Nash Equilibria for any given set of demand, plant and network conditions. *SPARK* can identify multiple equilibria because it tests *all* potential combinations of offers by generators deemed to be strategic in order to ascertain whether any given combination of offers represents a Nash Equilibrium. This may involve testing thousands of bidding combinations at a given level of demand. This exhaustive testing process is what sets *SPARK* apart

44 This corresponded to removing 3 x Seraya steam units and 1 x Senoko steam unit. Tuas' steam unit was retained in the market.

from many other dispatch models, which commence with a particular set of bidding strategies and then iterate bids until a Nash Equilibrium is found (if any).

The identification of multiple Nash Equilibrium by *SPARK* is a defining feature of the model, as even in the simplest games[45] multiple Nash Equilibria can arise. Where *SPARK* finds multiple equilibria, we report the average of the equilibria outcomes rather than any single Nash Equilibrium outcome to ensure our results are not distorted by extreme cases.

More detail on *SPARK* and our application of Game Theory is discussed in Appendix B – *SPARK* market modelling.

Modelling inputs

For a detailed description of inputs used in the market modelling exercise, please see Appendix C – Market modelling inputs.

Modelling calibration

For a detailed description of the calibration process for the market modelling exercise, please see Appendix D – Market modelling calibration results.

Modelling results

Full results and charts can be found in Appendix E – Setting the VCL for 2017 and 2018. This section presents a brief summary of the modelling results.

Our base case forecasts of the distribution of annual average prices are shown below. The distribution reflects uncertainty around generator forced outages (as discussed further in Appendix C – Market modelling inputs).

Figure 3 shows forecast outcomes with the unvested MSSL load unhedged, and Figure 4 shows forecasts with the MSSL load prudently hedged. Each figure depicts a forecast price distribution for each of calendar years 2017 and 2018 and for each VCL case. The price distribution is shown as a 'box and whisker' plot where the extreme ends of the whiskers represent the minimum and maximum forecast annual average price, and the boxes (with their internal vertical lines) represent the 25th, 50th and 75th percentiles of the forecast price distribution.

Our forecasts indicate that prices are unlikely to rise significantly if the VCL was lowered:

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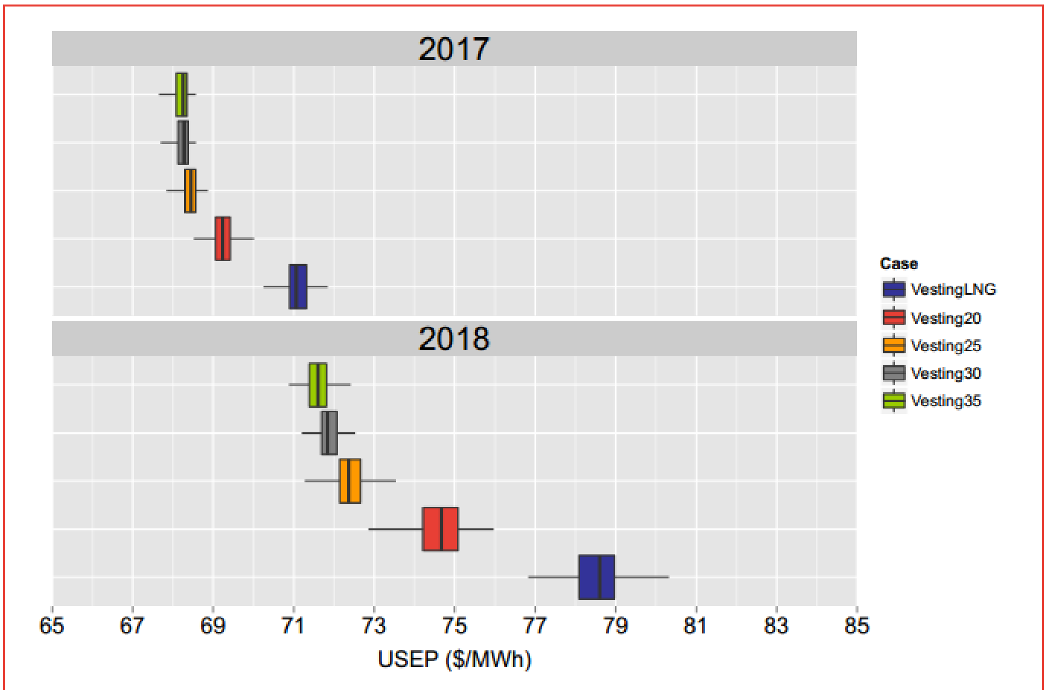
45 See Fudenberg, D. and J.Tirole (2000), *Game Theory*, Seventh printing, The MIT Press, p.18.

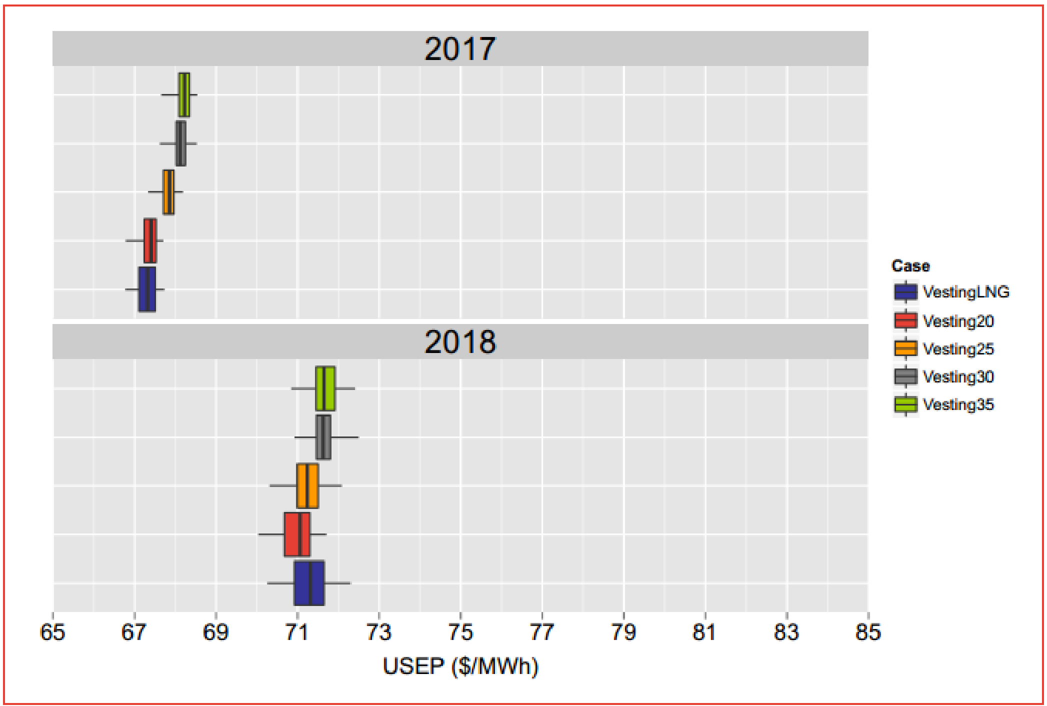
- Where unvested MSSL load is not hedged, price rises associated with a reduction in the VCL from 25% to the LNG vesting level would result in an annual average price increase of approximately $3/MWh in 2017 and $6/MWh in 2018.
- Where unvested MSSL load is prudently hedged, lowering the VCL does not result in any material price rises (in fact, we forecast a slight price decline).
- No prices under any VCL, with either hedged or unhedged unvested MSSL load, approach vesting price levels (which are around $129/MWh in 2017 and $130/MWh in 2018).
- Note that price rises in 2018 are consistent with increasing fuel prices, decreasing TOP quantities and increasing demand (see Appendix D – Market modelling calibration results for further discussion).

Figure 3: Base case forecast annual average USEP price distributions with unvested MSSL load unhedged



Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices

Figure 4: Base case forecast annual average USEP price distributions with unvested MSSL load prudently hedged



Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices

In the cases where the unvested MSSL load is not hedged, generators gain greater pool exposure due to falling net contract positions as the VCL is reduced. Gencos therefore have more incentive to exercise market power, increasing forecast pool prices as VCL is reduced. However, having the MSSL load prudently hedged means that any reduction in the VCL is offset, negating this effect. These results indicate that prudently hedging the MSSL load appears to be as effective as vesting contracts, under our base case assumptions.

We also modelled a number of sensitivities, as presented in Appendix E, where we observe the following:

- Bidding sensitivity case:
  - Where unvested MSSL load is unhedged, we observe material price rises consistent with greater levels of pool exposure in the market. In the Vesting LNG case for 2018 forecast price levels are above our comparative estimate of LRMC.
  - Where the unvested MSSL load is hedged, we observe no material price increases when dropping the VCL to 20%. However, we do observe minor price increases when further dropping the VCL to LNG vesting, reflecting some limited opportunities to engage in strategic bidding at this lower vesting level.

- Supply demand sensitivity case (see Figure 22):
  - This sensitivity was modelled for the MSSL prudently hedged case only. The modelling showed some cases where a lower VCL would lead to higher forecast prices. However, prices did not approach the comparative LRMC, despite prices being generally higher and more volatile in all VCL cases.

Finally, our recommendation has also been influenced by historical events involving high prices in the SWEM. Such events provide, to some extent, a natural experiment against which to benchmark forecast outcomes and can be informative in a wider sense. Our analysis suggests that historical high price events appear consistent with our modelled outcomes in the base and sensitivity cases.

4.5.3 Draft VCL recommendation

Our analysis suggests that there is only limited potential for the exercise of market power in the SWEM over 2017 and 2018 and that this is essentially completely limited to the extent that the unvested MSSL load is prudently hedged.

In consideration of the above, conditional on the prudently hedging the unvested MSSL load, we consider that there is scope to reduce the VCL to the LNG vesting level by the end of calendar year 2018.

If the unvested MSSL load is not hedged, our draft recommendation is for the VCL to be reduced to no lower than 20% by the end of 2018. This difference is attributable to our concerns regarding potential outcomes that arise in our sensitivity modelled cases.

Recommendation 1 – VCL for 2017 & 2018

We recommend that, conditional on prudently hedging the unvested MSSL load, there is scope to reduce the VCL to the LNG vesting level by the end of calendar year 2018.

If the unvested MSSL load is not hedged, we recommend that the VCL be reduced to no lower than 20% for calendar years 2017 and 2018.

4.6 Assessing the existing vesting contracts regime

This section reviews the existing vesting contracts regime against each of the evaluation criteria set out in Section 3. Our evaluation assumes that our draft recommendations regarding the VCL for 2017 and 2018 and the tendering of contracts covering unvested MSSL load would be adopted.

4.6.1 Effectiveness

Market power

As noted in Section 3.3, hedged Gencos have little to gain in the short run by withholding contracted capacity. In the long run, generators may achieve some benefits by withholding hedged or contracted capacity even where the spot price exceeds their SRMC. Nevertheless, all else equal, a higher VCL should mitigate Gencos' incentives to exercise market power. By promoting a more competitive market, a higher VCL should also reduce the incentives of non-Gencos to exercise market power.

For a given VCL, tighter supply-demand conditions may increase opportunities for exercising of market power subject to competitive tension. The extent to which this occurs in practice is an empirical question. Historically, we observe little evidence of the persistent exercise of market power. Our forward looking analysis shows that a key driver of the extent to which the vesting regime is required to mitigate market power is whether the unvested MSSL load is hedged or not.

VCL and MSSL load

As noted above, all else equal, a higher VCL should mitigate Gencos' incentives to exercise market power. However, to the extent Gencos respond to reductions in the VCL by entering into other (market) wholesale contracts or increasing their retail positions, changes in VCL may not have a large influence on Gencos' bidding behaviour. This is because the increase in Gencos' exposures to the wholesale price due to a lower VCL will be offset or substituted by their increased obligations under market contracts or retail positions.

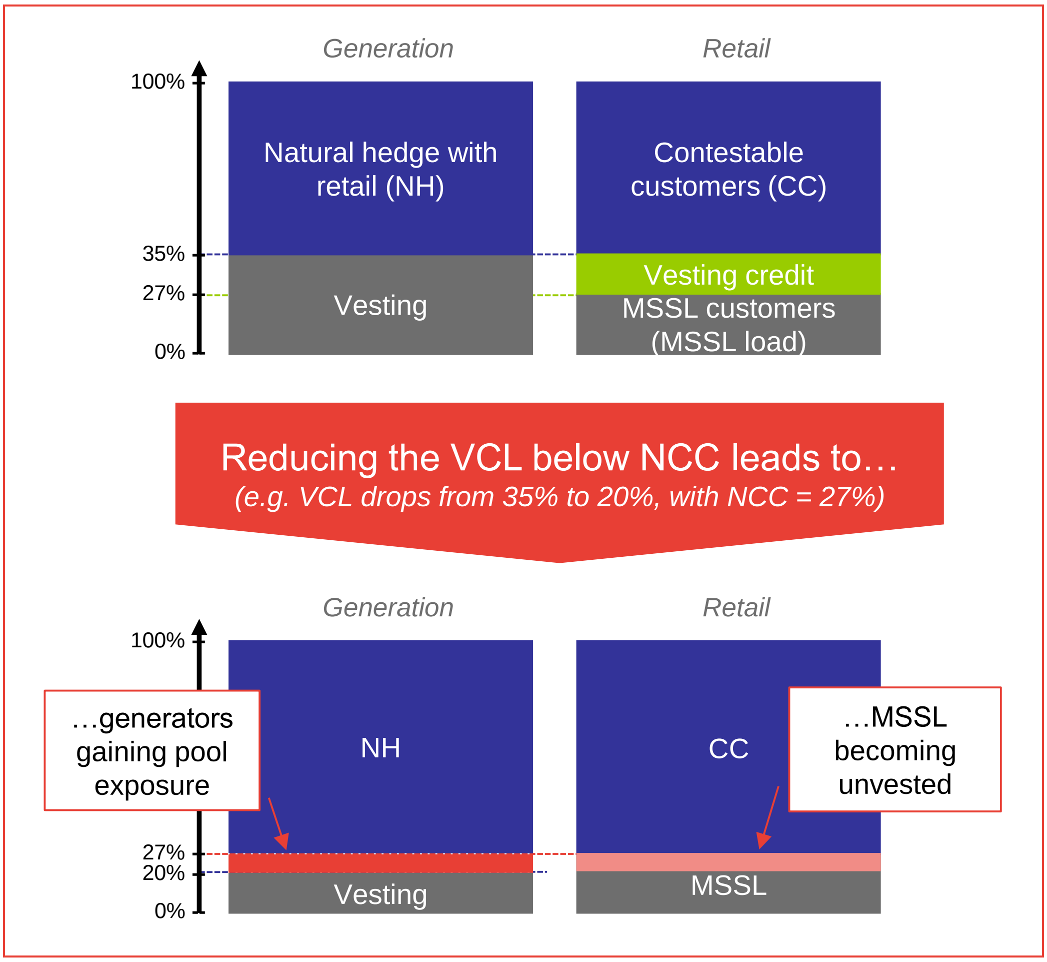
In a fully liberalised market, we would typically expect to observe retail load being approximately fully hedged by participants individually and in aggregate due to the exposure of retailers to asymmetric wholesale spot price risk. Thus if the VCL were reduced, we would expect to see an offsetting increase in market hedges to ensure aggregate retail load remained fully hedged.

Under the current vesting contracts regime, if the VCL exceeds the cover required to hedge total MSSL load, the unassigned contract quantity (and hence vesting debits and credits) is allocated to contestable customers. In 2014, MSSL load accounted for approximately 29% of total electricity consumption in Singapore.[46]

A key determinant of Gencos' incentives to exercise market power under the current vesting contracts regime is the difference between the VCL and the MSSL load. When the VCL exceeds the MSSL load, reductions in the VCL tend to be offset by commensurate increases in the Gencos' retail load, leaving the Gencos' aggregate exposures to the spot price relatively unchanged. However, when the VCL falls below the MSSL load and if that difference (the unvested MSSL load) is not otherwise hedged or offset by an increase in the retail load or financial hedges of the Gencos, Gencos can find themselves with stronger incentives to exercise market power. This is illustrated in Figure 5.

46 EMA, *Singapore Energy Statistics 2015*, June 2015, available from the EMA website at https://www.ema.gov.sg/cmsmedia/Publications_and_Statistics/Publications/SES2015_Final_website_2mb.pdf (accessed 10 February 2016), p.36.

Figure 5: Interaction between VCL and MSSL load



Source: Frontier Economics

As identified in Section 4.5.2 and Appendix E, our modelling of the 2017 and 2018 period shows that bidding behaviour is likely to remain fairly competitive even if the VCL were reduced, subject to the MSSL load being prudently hedged. That is, so long as MSSL load is prudently hedged, reducing the VCL does not result in material price increases in our base case scenario (Figure 19). In our sensitivity cases, the VCL can be reduced to some degree below 25% without substantial price rises (see Figure 21 and Figure 22). Conversely, where MSSL load is not prudently hedged, significant price rises can be observed as a result of lowering the VCL. However, even then, prices remain substantially below the vesting contract price (see Figure 18 and Figure 20).

Ultimately we conclude that the vesting contracts regime – when combined with the hedging of MSSL load – is broadly effective at mitigating market power across a wide range of VCLs. That range narrows somewhat if the MSSL load is not hedged.

Allocation

The vesting contracts are currently on the basis of licensed or planned capacity at market start as discussed in section 4.3.8. This allocation is technology neutral, which in practice means that CCGT, OCGT and steam generating units can all support a vesting allocation on an equal footing to the extent that the plant is maintained and available to be recalled to market on short notice.

In the case of the steam units, this raises two potential issues.

Firstly, in the current oversupplied market, the steam units run infrequently and typically require at least 24-48 hours to return to operation. The majority of high price events in the SWEM are highly transient in nature, occurring over a time frame of hours, not days. Given that steam units are subject to return times in excess of their ability to respond to such transient events, there seems to be a reduced argument for allocating vesting contracts to such capacity to limit market power. The alternative would be to allocate the vesting contracts on the basis of capacity that can more credibly respond to short term price events, namely the CCGT and OCGT capacity in the market. Our modelling (see Figure 28) indicates that such an allocation would marginally improve the effectiveness of the vesting contracts for a given VCL.

Secondly, and potentially more importantly, the allocation of vesting contracts to plant which may no longer be economically required in the market may lead to inefficiencies with regard to decisions to mothball or permanently retire the units. This could have longer term implications for dynamic efficiency and resource adequacy as discussed further below.

We conclude that there may be grounds to improve the effectiveness of the vesting contracts regime through alternative contract allocations.

Localised market power

As discussed in Section 3.1 and above, the scope for localised market power depends on the level and distribution of generation and demand, the structure and location of generation portfolios, and the frequency and duration of binding transmission constraints.

Our analysis of historical data shows that under the existing vesting contracts regime, significant price separation (which could be an outcome of the exercise of localised market power) occurs only very occasionally in the SWEM. The most significant events arose in October 2015 (see Figure 30) and involved a relatively small number of events (see Figure 32). Infrequent periods of significant price separation are usually attributed to exceptional circumstances such as generation and/or transmission outage events. We note that transmission congestion is a relatively minor issue in the SWEM and, as a general rule, transmission constraints are generally built out over the medium term.

The effectiveness of the vesting regime at mitigating localised market power is in principle the same as the ability of the regime to mitigate global market power in that, all else equal, a higher VCL mitigates Gencos' incentives to exercise localised market power. This outcome arises from the fact that the vesting contracts are settled against each Genco's dispatch weighted nodal prices, the VCRP. This ensures that potential profits arising from exposure to higher nodal prices are offset by increased outgoing settlement payments. In contrast, were the vesting contracts settled against USEP, generators would still be exposed to the difference between a 'high' nodal price and 'low' USEP for output that was covered by vesting contracts. On this basis we conclude that the vesting regime is equally effective at mitigating incentives to exercise both global and local market power for a given vesting contract level.

4.6.2 Dispatch efficiency

A market design that effectively constrains the exercise of market power will typically also promote dispatch efficiency. If generators do not engage in physical withholding and their offer prices reflect their SRMCs, plant dispatch should be economically efficient. We therefore conclude the vesting contracts regime is likely to be consistent with achievement of dispatch efficiency in the SWEM.

4.6.3 Resource adequacy

As noted above, the resource adequacy assessment criterion refers to the influence of a measure on financial incentives for investment (and retirement) decisions with respect to efficiently meeting desired reserve levels and reliability standards. Resource adequacy does not relate to the financial sustainability of incumbent Gencos *per se*.

We consider that there are several ways in which the current vesting contracts regime could influence future resource adequacy in the SWEM:

- First, if the regime systematically prevents efficient plant from earning an adequate return.
- Second, if the regime otherwise deters or distorts plant investment and/or retirement decisions.

Systematic effects on returns of efficient plant

As noted in Section 4.3.6 above, the EMA presently sets the VCL so as to steer the USEP towards the LRMC of efficient CCGT. This principle has been the subject of criticism from the Gencos and their consultants, on the basis that such an approach systematically prevents the Gencos from recovering their efficient costs because it means:[47]

- Spot prices drop below LRMC in periods of surplus and
- VCL is raised for the USEP to target LRMC when the market tightens.

Therefore, spot prices are not able to match LRMC on average through the investment cycle.

In our view, this argument might have some validity if the EMA was willing to raise the VCL aggressively and potentially up to 100% to stabilise the USEP or push it down. However, the EMA has noted that:

> The VCL does not cap the pool price at the Vesting Price (or LRMC), as pool prices can rise above the Vesting Price under tight market condition as observed in 2011 and 2012, with the USEP averaging at 10.1% and 3.7% above the Vesting Price respectively.

We interpret this to mean that the while the EMA will increase the VCL to bring the USEP back down towards LRMC, it will not do so in an unconstrained manner. The EMA will not raise the VCL aggressively to strictly 'cap' the USEP at LRMC ***and in fact has not done so in the past***. This interpretation is supported by the figures cited in section 4.3.6, which show that the EMA has only once raised the VCL, and even this was by just 5%. Therefore, we consider that the EMA's approach to setting VCL need not lead to Gencos systematically under-recovering their efficient costs.

Impact on incentives for efficient future investment decisions

Despite our assessment that in practice the vesting contracts regime does not systematically prevent generators from recovering efficient costs, we query the principle of raising or lowering the VCL to usher the USEP towards LRMC. While this should help smooth fluctuations in wholesale spot prices, there is little economic justification for average wholesale prices to converge around LRMC under conditions of either excess or short supply. Rather, investors would receive

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47 EMA, *Review of the Vesting Contract Level for the Period 1 January 2015 to 31 December 2016, Final Determination Paper*, 22 September 2014, Appendix 1 and 2.

more appropriate signals if the average USEP fell below LRMC at times of excess supply and rose above LRMC at times of short supply. Arguably, using the vesting contracts regime to target LRMC, and consequently mitigate the extent of both falls below and rises above LRMC, acts to dampen efficient price signals in the market. We address this weakness in our potential alternative approach to setting the VCL in Section 6.4.

Another concern about the existing vesting regime stems from the perverse incentives for Gencos to keep inefficient plant in service and to oppose efficiency-enhancing reforms. These incentives arise due to a combination of the following two factors:

- Vesting contract prices are much higher than the prevailing USEP and
- Vesting contract quantities allocated to Gencos are dependent on whether they retain in service the capacity used for the allocation of vesting quantities.

Together, this means that Gencos may prefer to keep existing inefficient plant in service, solely to maximise their allocation of financially favourable vesting contracts, rather than retiring those plant and potentially replacing them with more efficient plant. It also means that Gencos have an interest in opposing reforms that involve reducing the VCL and/or the vesting contract price and replacing vesting contracts with tools suitable to a more mature market.

4.6.4 Intrusiveness and administrative burden

The essential character of vesting contracts is that they are *imposed on* vested Gencos with the MSSL being the only counterparty. Due to the lack of choice participants face in being a counterparty to a vesting contract and in relation to the volume and price of a vesting contract, vesting contracts represent a relatively intrusive measure for mitigating market power.

The design and operation of vesting contracts also involves a degree of complexity and administrative burden on participants, market operators (via settlement) and policy-makers (due to reviews).

A further consideration is that by providing both generator and retailer counterparties with a hedge against their exposures to the wholesale spot price, vesting contracts obviate the need for both counterparties to enter market-based risk management instruments. Accordingly, vesting contracts tend to inhibit the organic development of a wholesale contract market.

It is for these reasons that vesting contracts are usually authorised as a time-limited mechanism in most of the markets where they have been applied (e.g. England & Wales Pool and the Australian National Electricity Market (NEM)). In Australia, the regulator (the Australian Competition and Consumer Commission), was reluctant to authorise the continuation of vesting contracts beyond the time when small customers became contestable.

We conclude that as long as some form of vesting contracts regime is retained, there is little that can be done to materially reduce the intrusiveness of the arrangements.

4.6.5 Transparency and predictability

The current vesting regime in the SWEM operates in a reasonably transparent manner. However, there is significant uncertainty associated with the biennial resetting of the VCL. The uncertainty arises because the EMA Vesting Procedures refer to a number of potentially offsetting factors relevant to how the VCL should be set, including the LRMC of a new entrant and the desire for a gradual monotonic reduction in the VCL.

The impact of this uncertainty on Gencos is heightened to the extent that the price of vesting contracts is higher than spot prices, as has been the case in recent years. This means that the changes in the VCL can have large effects on the Gencos' financial positions.

We conclude that there may be alternative ways to set VCL that would provide greater transparency and predictability to participants than the current arrangements.

4.7 Minor enhancements to the current regime

This section outlines potential minor clarity enhancements to the current vesting contracts regime. We discuss more significant recommended changes to the vesting contracts regime in section 6.

A number of minor incremental enhancements could be made to the current vesting contracts regime. Although the EMA Procedures set out the range of factors that influence its setting of the VCL, it may be worthwhile for the EMA to restate in other documents and on its website that bringing USEP into line with the LRMC of an efficient entrant is not the only consideration driving the setting of the VCL. This would help stakeholders to be better informed of the considerations involved in setting the VCL under the existing regime.

Our analysis suggests that raising the VCL above 30% is unlikely to exert any incremental mitigating effect on the exercise of market power (see Figure 18 and Figure 19). This is because above a 30% VCL, incremental vesting cover primarily involves a substitution from a direct retail position to a vesting position that is credited against retail load.

Additionally, we conclude that where possible the VCL should be changed gradually. This could involve a move to a glidepath adjustment, for example changing VCL by 5% via a series of four quarterly changes of 1.25% each. It could also involve caps on annual or biennial changes to VCL.

Reflecting these conclusions, one way to provide investors with greater confidence about the size and direction of changes to the VCL would be to modify the EMA Procedures to limit (to some extent) both:

- The maximum VCL that the EMA would be permitted to raise the VCL to and
- The maximum change in VCL that the EMA could implement over any given two-year period.

Design parameter 1 – Minor enhancements to the existing vesting contract regime

We recommend that the EMA Procedures be amended to reflect:

- A maximum VCL limit and
- The inclusion of directions or limits on the rate of change of the VCL.

4.8 Summary and conclusions

The current vesting contracts regime operates in the context of an energy-only market with licence caps on the capacity of the three dominant Gencos. The arrangements as a whole have performed well in limiting the exercise of market power with only a handful of instances where transient market power may arguably have been exercised. The regime has also performed well in ensuring dispatch efficiency. However, the vesting contracts regime is fairly intrusive and it can be difficult for participants to predict future changes in the VCL. Finally, there is a question as to whether the current vesting allocation is the most effective approach to mitigating market power and whether the allocation of currently financially advantageous vesting contracts to steam capacity creates perverse incentives to maintain uneconomic plant in the market, adversely affecting long term resource adequacy.

Our analysis suggests that there is only limited potential for the exercise of market power in the SWEM over 2017 and 2018 and that this is essentially completely limited to the extent that the unvested MSSL load is prudently hedged. On this basis, there is scope to reduce the VCL to the LNG vesting level by the end of 2018.

5 Market power mitigation mechanisms

This Section outlines a range of alternative tools that could be used to mitigate market power in the SWEM. It begins by providing an overview of the tools used to mitigate market power in other jurisdictions (Section 5.1), before considering the applicability of the various mechanisms to the SWEM. It discusses in turn conditional price caps (Section 5.2), bidding restraints and obligations (Section 5.3) and other measures (Section 5.4). Finally, it presents our summary and conclusions (Section 5.5).

5.1 International market power mitigation mechanisms

Frontier Economics reviewed the mechanisms used to mitigate market power in a range of international electricity markets. In particular, we considered the energy only markets of the Australian NEM, New Zealand Electricity Market (NZEM) and the Texas ERCOT. We also considered the energy and capacity markets of the PJM Interconnection (PJM) and the Irish Single Electricity Market (SEM). Table 3 characterises the electricity markets considered, and summarises the mechanisms used to mitigate market power in each case. Further detail is provided in Appendix A.

At the outset it is important to recognise the design of a market necessarily influences the type of market power mitigation mechanisms observed in that market. For example, in markets where a separate capacity mechanism provides the ability for participants and future investors to recoup some of their fixed costs, mandated short-run marginal cost (SRMC) bidding rules are more common. Conversely, energy-only markets tend to incorporate higher (or no) price caps and less restrictive bidding requirements, to enable participants and future investors to recoup the cost of their investments.

Table 3: Summary of review of international approaches to market power mitigation

Jurisdiction	Market design	Market special features	Market price cap (MPC)/Market price floor (MPF)	Conditional price caps	Bidding restraints	Other measures
Singapore NEMS	Energy only Gross-pool Generator nodal pricing Self-commitment FTRs N/A	High levels of privatisation Highly vertically integrated Capacity ~13,500MW	MPC: S$4,500/MWh MPF: S$-4,500/MWh	N/A	Prohibition of anti-competitive agreements and abuse of dominant position	Vesting contracts Market capacity caps on three largest participants Market monitoring
Australian NEM	Energy only Gross-pool Regional pricing Self-commitment Non-firm FTRs	High levels of privatisation Increasingly vertically integrated Long & stringy Capacity ~45,000MW	MPC: AU$13,800/MWh, escalated with inflation MPF: AU$-1,000/MWh	Administered price cap of A$300/MWh triggered when the cumulative price threshold of A$207,000 is reached in a rolling 7 day period	Bidding in good faith provisions prohibit false and misleading offers	Transitional vesting contracts at NEM start Regulated wholesale contracts for large state-owned generator HydroTas Market monitoring
New Zealand	Energy only Gross-pool Full nodal pricing Self-commitment Firm FTRs (limited nodes)	Significant vertical integration Capacity ~5,100MW	De facto price cap of NZ$3,000	Scarcity pricing during times of emergency load shedding MPF = NZ$10,000/MWh MPC = NZ$20,000/MWh	Undesirable trading situations Safe harbour provision for bidding behaviour in pivotal supplier situations	Compulsory hedging regime at market start Market monitoring

Jurisdiction	Market design	Market special features	Market price cap (MPC)/Market price floor (MPF)	Conditional price caps	Bidding restraints	Other measures
Texas (ERCOT)	Energy only Net pool Full nodal pricing Self-commitment Non-firm FTRs	Small proportion of energy (~5%) submitted into energy pool. Capacity ~90,000MW	High systemwide offer cap of US$9,000/MWh which applies under system normal conditions.	Low systemwide offer cap (higher of US$2,000/MWh or 50 times daily natural gas price index) triggered if Peaker Net Margin exceeds a pre-defined amount during the year.	Two-step market power mitigation mechanism over non-competitive constraints Physical and economic withholding prohibited under the Texas Administrative Code Voluntary mitigation plans	Small fish swim free: Those with <5% market share deemed not to have market power. Market monitoring
PJM	Energy + capacity Net pool Full nodal pricing Central-commitment Firm FTRs	Significant vertical integration Meshed network Capacity ~177,000MW	MPC = US$2,000/MWh Make whole payments provided if costs >US$2000/MWh.	Reserve shortage price = US$3,700	Three pivotal supplier test for "local market power" over transmission constraints Anti-manipulation rule	Market monitoring
Ireland SEM	Energy + capacity Gross pool Single pricing region Central-commitment FTRs N/A	Two government-owned generators with large market share Interconnected with GB via 500MW East-West interconnector Capacity ~10,000MW	MPC = €1,000/MWh MPF = €-100/MWh	N/A	Mandated SRMC bidding	Directed Contracts Vertical ring-fencing Three-step tiered local market power mitigation process Market monitoring

Source: Frontier Economics

Market power mitigation mechanisms

The review of international approaches to market power mitigation identified a range of tools used to mitigate market power:

- Conditional price caps, including:
  - Scarcity pricing
  - Cumulative price threshold caps.
- Bidding restraints and obligations, including:
  - Mandated SRMC bidding
  - Pivotal and/or constrained supplier tests
  - Voluntary mitigation plans
  - General behavioural obligations.
- Other mechanisms, including:
  - Capacity or concentration caps
  - Directed contracts.

The applicability of each of these mechanisms to the SWEM is discussed in turn in Sections 5.2 to 5.3.4 below.

5.2 Conditional price caps

Unlike market price caps which apply at all times, conditional price caps, such as scarcity pricing and cumulative price caps, apply for a defined period of time subject to certain conditions being met.

5.2.1 Lower market price cap plus scarcity pricing

A system-wide price cap currently applies in the SWEM. An alternative approach would involve the introduction of a conditional price cap linked to scarcity, similar to the scarcity pricing approach adopted in the NZEM. Under such an approach a lower market price cap (e.g. S$1,000/MWh) could be applied under most circumstances, but market prices could be permitted to rise to a higher scarcity price cap (e.g. S$10,000/MWh or more) under pre-defined conditions, such as load shedding. This would attenuate incentives to engage in economic withholding of capacity under normal operating conditions, while allowing spot prices to rise sufficiently to remunerate generation capacity during those times when supply was insufficient to meet demand.

However, the mandated reserve plant margin of 30% in the SWEM means scarcity events are highly unlikely. Introducing a lower anytime market price cap plus scarcity pricing in this context may therefore be equivalent to lowering the market price cap.

Accordingly, this approach is not considered as part of the packages of options evaluated for the SWEM.

5.2.2 Cumulative price caps

The introduction of a cumulative price threshold and administered price cap, similar to that adopted in the Australian NEM, is another potential approach to conditional price capping. Under such arrangements an administered price cap could be imposed when the sum of half-hourly prices over a defined period exceeds a specific value.

Price caps that are imposed following a period of prolonged high prices have the advantage of being relatively straightforward. However, they offer little benefit in the way of immediate direct relief from the exercise of transient or localised market power. Conditional price caps in the Australian NEM are intended as a mechanism to manage extreme events, such as a prolonged period of lost load events, rather than a tool to manage generator market power. Moreover, those participants with legitimate costs above the administered cap (e.g. peaking plant) may be eligible for compensation, adding an additional level of complexity.

For these reasons, we do not consider conditional price caps as part of the packages of market power mitigation options evaluated for the SWEM.

5.3 Bidding restraints and obligations

Many markets have bidding restraints and obligations as part of their market rules, ranging from explicit bid control mechanisms, such as mandated SRMC bidding and pivotal supplier tests, to more general mechanisms, including voluntary mitigation plans and behavioural obligations.

5.3.1 Mandated SRMC bidding

Mandated bidding at SRMC is imposed in several combined energy and capacity markets, including the Irish SEM and the Western Australian Wholesale Electricity Market. In theory, such measures should promote efficient dispatch by ensuring plant bid in merit-order. However, for such obligations to avoid harming investment incentives and resource adequacy they need to be coupled with a separate capacity mechanism.

Introducing a capacity market would represent a fundamental change to the design of the SWEM. Nevertheless, market participants concerned that the energy-only market design in Singapore is not delivering an adequate return on capital have suggested the introduction of a capacity market merits further consideration.

However, there is little evidence that jurisdictions with separate capacity and energy markets produce more efficient or reliable outcomes than jurisdictions with well-designed energy-only markets. A capacity mechanism is necessarily intrusive and administratively burdensome, as it requires a centralised decision-maker to spend large amounts of time and resources on setting and revising a wide range of parameters, including:

- The required amount and location of generation capacity or demand-side response across the market.
- The appropriate level and form of remuneration payable to eligible capacity – including whether this varies across technologies – and the frequency with which remuneration is revised or updated.
- The availability conditions on generators for receiving capacity payments.
- The magnitude of any penalties for unavailability when capacity is called or required.
- The value of capacity in excess of the required amounts, and the price that should be paid to capacity in the event of an excess.
- The value of capacity shortfalls, and the capacity price that should be paid to encourage investment.
- Whether the same remuneration should be offered to existing and new capacity under excess and shortage conditions.

Further, the more decentralised means by which incentives for generation are set in energy-only markets enables participants to predict future incentives with greater confidence than where capacity markets exist and policy-makers may choose to modify parameters in a less transparent manner.

For these reasons, we consider that the introduction of a capacity market in Singapore should need to satisfy a high threshold. In our view, the limited extent of market power observed in the SWEM to date, combined with the high prevailing level of reserve plant margin and the scope to test a range of other mitigation measures mean that this threshold has not been met to date. Accordingly, we do not consider options typically adopted in two-market designs, such as mandated SRMC bidding, further in this report.

5.3.2 Pivotal supplier tests

In several markets, including PJM and ERCOT, a pivotal or constrained supplier test is imposed to manage localised market power. These tests are used to assess whether a generator has localised market power over a transmission constraint or within a region. When this occurs, the pivotal supplier typically has its offers capped at a level more reflective of its SRMC, effectively mitigating localised market power that arises due to transmission constraints.

The assessment of a generator's 'pivotality' involves an automated assessment within the dispatch engine of the relevant generators' capacities relative to the transmission constraint in question. The design of the mechanisms and level of the cap must be carefully considered to ensure appropriate investment incentives remain, and that incentives for participants to game the test or for regulators to over-mitigate normal market behaviour do not occur.

We consider pivotal supplier tests in more detail as part of the packages of market power mitigation options considered in Section 6.

5.3.3 Voluntary mitigation plans

The voluntary mitigation plans used in the Texas ERCOT detail the conditions and market environment under which the generator will supply power to the energy market and the prices at which this energy will be supplied, while providing for some flexibility.

Voluntary mitigation plans can be effective in reducing the exercise of market power, however their efficacy relies on the goodwill of the participant in question. Accepting or agreeing voluntary mitigation plans would consume the time and resources of the EMA, with no guarantee that the plan in question would prevent the exercise of market power. Moreover, it is likely that the Gencos would be reluctant to submit voluntary mitigation plans without the prospect of more intrusive and onerous measures.

Therefore, we do not consider voluntary mitigation plans as part of the packages of options further examination.

5.3.4 General behavioural obligations

A number of markets, including the Australian NEM and NZEM, impose broad behavioural obligations on generators that seek to prevent or deter them from exercising market power.

A key drawback with such obligations is that they are often worded in a pejorative or otherwise subjective manner, which leads to uncertainty about when and how they will be applied. Often, what appears to a regulator as 'manipulative' or 'bad faith' conduct is consistent with businesses seeking to maximise profits under prevailing market conditions. The meaning of these provisions is often only established in circumstances where the regulator has sanctioned a participant and the participant has appealed the regulator's interpretation, as has occurred in both Australia and New Zealand. Even then, a court's finding only resolves the direct issue in dispute between the parties; there may be other aspects of the obligations that are not resolved, resulting in further dispute and litigation. The ongoing uncertainty arising from behavioural or conduct obligations can undermine incentives for both efficient dispatch and investment decisions. Such obligations can also be administratively burdensome, such as the new Australian NEM obligation to make and keep contemporaneous records of the circumstances surrounding late rebids.

Accordingly, we do not consider general behavioural bidding obligations as part of the packages of options evaluation in Section 6. In any case, the EMA is able to examine, *inter alia*, and take action against conduct that may constitute an abuse of a dominant position under Section 51 of the *Electricity Act* as discussed in Section 4.4.

5.4 Other measures

There are a number of other measures used in various markets which merit further consideration, including capacity or concentration caps and directed contracts.

5.4.1 Capacity or concentration caps

Capacity or concentration caps can be used as a mechanism to limit the market shares of dominant generators. As discussed in Section 4.4 licensed capacity caps limit the market share of capacity of the three dominant Gencos in the SWEM. Although such caps are not a feature of the markets reviewed for this study, concentration caps have been applied in other jurisdictions. Our international review found that:

- **Alberta** applies a concentration cap whereby no market participant is permitted to control more than 30% of the total generation capacity.
- The **United States** Department of Justice (DoJ) and Federal Trade Commission (FTC) use Herfindahl-Hirschman Indices (HHIs) based on the merger guidelines issued by the DoJ and FTC in 2010 (2010 Merger Guidelines).[48] These guidelines impose the following HHI thresholds when analysing horizontal market power:
  - Absolute HHI thresholds:
    - < 1,500: Unconcentrated

[48] See FERC, *Analysis of horizontal market power under the Federal Power Act,* Order Reaffirming Commission Policy and Terminating Proceeding, Docket No. RM11-14-000, issued February 16, 2012 (FERC (2012)), p.5.

  - 1,500 – 2,500: Moderately Concentrated
  - > 2,500: Highly Concentrated
- Changes in HHI *potentially* raising competitive concerns:
  - > 100 in Moderately Concentrated markets
  - 100 – 200 in Highly Concentrated Markets
- Changes in HHI *presumed* to enhance market power:
  - > 200 in Concentrated Markets

- The **United States** Federal Energy Regulatory Commission (**FERC**) uses more conservative HHI thresholds imposed in the 1992 version of the Merger Guidelines. These are:
  - Absolute HHI thresholds:
    - < 1,000: Unconcentrated
    - 1,000 – 1,800: Moderately Concentrated
    - > 1,800: Highly Concentrated
  - Changes in HHI *potentially* raising competitive concerns:
    - > 100 in Moderately Concentrated markets
    - 50 – 100 in Highly Concentrated Markets
  - Changes in HHI *presumed* to enhance market power:
    - > 100 in Concentrated Markets

  FERC has explained that it considers the 1992 thresholds are more appropriate for analysing electricity markets, primarily due to the high inelasticity of real-time electricity demand.[49]

Capacity concentration caps offer a relatively transparent means of promoting competitive behaviour and outcomes over time. Although such caps are intrusive at an ownership level, they have virtually no impact on generators' day-to-day operating decisions. The key drawback of capacity or concentration caps is that they are less effective in mitigating market power and ensuring dispatch efficiency in the very short term.

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49 FERC (2012), p.24.

Capacity and concentration caps are therefore considered as part of a package of market power mitigation tools evaluated in Section 6.

5.4.2 Directed contracts

Directed contracts are CfDs allocated to large, incumbent generators in the Irish SEM to mitigate the incentive to exercise market power. The quantities of directed contracts imposed on each generator are determined using a concentration model which determines a total contract quantity to achieve adjusted Herfindahl-Hirschman Index (HHI) target. Each participant's contribution to this adjusted HHI is taken as its unvested capacity, with vested capacity assumed to contribute zero to the adjusted HHI. As such, the adjusted HHI is inversely proportional to the levels of direct contracts imposed on the market with the adjusted HHI always lower than the 'raw' HHI as it assumes that vested capacity does not contribute to concentration. A worked example of this formula is presented in section 6.4.1.

In the SEM, the target adjusted HHI has been set at a value of 1,150. This target value was deemed to provide a suitable level of directed contracts upon commencement of the regime and has not been subsequently adjusted over the life of the arrangements on the basis that market power is considered to be effectively managed at the 1,150 target level.

Directed contracts are very similar to vesting contracts, and are therefore effective at mitigating market power at appropriate levels of contract cover. However, they are relatively intrusive. Nevertheless, the transparent and mechanistic approach to determining the level of imposed contract cover under the directed contracts approach represents an alternative to the current arrangements to determining the VCL.

We consider the application of a concentration model to determine the VCL in more detail in Section 6.

5.5 Summary and conclusions

A wide range of approaches are used to mitigate market power in electricity markets around the world. However, many of these approaches are not applicable to or are unsuitable for the SWEM. Conditional price caps, such as scarcity pricing and cumulative price thresholds, are unlikely to be effective in mitigating market power in the SWEM. Bidding rules imposed in capacity markets, such as a requirement for generators to bid at SRMC are not appropriate for Singapore's energy-only market. Voluntary mitigation plans are likely to have limited efficacy in mitigating market power, and general behavioural obligations on generator bidding have proved problematic in the Australian

NEM and NZEM. Accordingly, these mechanisms are not considered in the package of tools for mitigating market power discussed in the next Section.

In contrast, there are several market power mitigation tools which are likely to facilitate the management of market power in the SWEM. Pivotal supplier tests are successfully applied to manage localised or transient market power relating to transmission constraints. Capacity or concentration caps present a relatively unobtrusive method for preventing structural market dominance. The concentration model applied to determine the level of directed contract cover in the Irish SEM may provide a more transparent and mechanistic approach to determining the VCL. Pivotal supplier tests, concentration caps and concentration models therefore form part of the packages of market power mitigation tools discussed in the next Section.

6 New approaches to mitigating market power in the SWEM

Taking our review of the current vesting contract regime in Section 4 as the starting point, this Section introduces and assesses a number of alternative 'packages' of measures that could be used to mitigate market power in the SWEM. Section 6.1 considers the comments from the draft report, before the packages are briefly introduced in Section 6.2. Sections 6.4 to 6.6 then describe each package in greater detail and assess the package according to the evaluation framework presented in Section 3.4. Section 6.7 presents our summary and conclusions.

6.1 Comments on the draft report

Many submissions made comments on the detail of the packages presented in this section of the draft report. We consider in turn below the specific comments made relating to the improved vesting contract regime, the balanced market regime and the combined approach. We then consider comments relating to common features of the packages, including the proposed market share capacity cap and the approach to hedging unvested MSSL load.

6.1.1 Improved vesting contract regime

YTL PowerSeraya comment that the calculation of the VCL under the combined approach would be "complicated and subjective".[50] YTL PowerSeraya argue the HHI of 1,250 "feels very low as a benchmark for determining that participants have market power which needs to be controlled", and would result in a VCL which is unlikely to be effective in mitigating market power.[51]

In response we note the HHI methodology is more systematic and transparent than status quo. The mechanisms of the formula are completely objective, rather than subjective, which is a deliberate intention of the design. Importantly, the threshold can be set objectively and transparently, addressing many of the shortcomings of the current vesting contract regime. The HHI threshold of

50 Submission from YTL PowerSeraya, p6.

51 Submission from YTL PowerSeraya, p6.

1,250 has been set with regard to international comparators, taking into account the characteristics of the SWEM. The modelling analysis presented in Section 4.5 and Appendix E – Quantitative analysis results demonstrates the competitive market outcomes are likely at a VCL of 17%, subject to the unvested MSSL load being hedged. We note that it is inconsistent to argue that a VCL of 17% is too low, and therefore unlikely to be effective in managing market power, while simultaneously suggesting that an HHI threshold of 1,250 is also 'low', since raising the HHI threshold would have the effect of lowering the calculated VCL. We demonstrate this effect in the worked example provided in Section 6.4.1.

Comments on the proposal to reallocate vesting contracts to effective capacity under the improved vesting contract regime vary widely, with the big three Gencos opposing the suggestion and other participants supporting the proposed change. Senoko Energy and YTL PowerSeraya comment that allocating vesting contracts to effective capacity would be likely to prompt the shutdown of steam turbines, removing generating units that have the capacity to burn alternative fuels, and delay the shutdown of less efficient plant. In contrast Keppel, SembCorp and Tuaspring support the allocation of vesting contracts according to efficient capacity on the basis it would be likely to encourage efficient retirement and investment decisions.

We agree with the comment that allocating VCL based on effective capacity is more likely to encourage efficient retirement and investment decisions. The retention of inefficient steam units in the market may deter new entry of more efficient generation capacity, and the slow response time of the units has the potential to compromise the reliability of the Singapore power system. In addition, our modelling shows that there is no material difference in price outcomes between the two allocation methods. We therefore continue to recommend the allocation of vesting contracts based on effective capacity under the improved vesting contract regime.

6.1.2 Balanced market regime

Participant views on the characteristics of the balanced market package and the recommendation to adopt the balanced market regime vary widely. We address those comments relating to the recommendation to adopt the balanced market regime in Section 7.1.

In terms of comments related to the specific characteristics of the balanced market regime, Keppel suggest the remaining BVQ under the balanced market regime be allocated based on effective capacity, consistent with the approach proposed for the improved vesting regime.

In response, we note that BVQ are limited under the balanced market regime, and are likely to be phased out in the near term. We recognise the likely benefits of reallocation, which we discuss in the context of the improved vesting contract regime. However, given the reduction in vesting quantities under the balanced market regime we continue to recommend it is unlikely to be beneficial to incur the disruption associated with reallocating BVQ based on effective capacity.

6.1.3 Combined approach

Keppel, SembCorp and PacificLight Power all comment on the proposed arrangements for mitigating localised market power. The submissions note that while a pivotal supplier test is likely to be time consuming, costly and may be unnecessary in the future due to transmission investment, price separation remains a material issue that needs to be addressed in the short-term. The participants suggest a range of potential approaches, including an interim mechanism (like option 1 or 5 from the Rule Change Panel paper CP61: *Proposed Measures to Mitigate Price Separation*), a separate review on the issue of price separation, or the removal of nodal pricing.

We note that the core issue driving these participant comments relates to transmission congestion. Under the existing market rules, transmission congestion currently manifests as price separation between generation nodes, resulting in price basis risk which is a concern for the smaller generation portfolios, particularly given that load is settled on an average price basis at USEP. However, the interim measures suggested will change the symptoms of transmission congestion, rather than remove the underlying congestion. For example, if nodal pricing was replaced by uniform market pricing for generation, the basis risk currently faced by generators would translate into dispatch risk (risk in volumes rather than prices). This is discussed further in section 6.6.1 below.

The pivotal supplier test proposed under the combined approach will potentially mitigate price separation to the extent that it is caused and/or exacerbated by localised market power. However, we do not see evidence of the systemic exertion of localised market power by any participants, historically or on a forward modelling basis. Price separation has not been a frequent occurrence in the SWEM (occurring only 1.1% of all trading periods in 2015), nor is it likely to become a material problem in the future as transmission investment is likely to ensure constraints will be alleviated over time. There was no evidence of price separation in our forward looking modelling analysis. Nevertheless, it may be beneficial to retain a pivotal supplier test as an option which could be triggered under market conditions that could facilitate localised market power, such as increased and persistent transmission constraint in the future.

6.1.4 Capacity cap

YTL PowerSeraya was the only participant to comment on the proposal to replace the current MW capacity limits in the generation licences of the three largest Gencos with a capacity cap that would apply uniformly across all generation licences. YTL PowerSeraya describe the imposition of a market capacity share cap of 25 precent as "unjustified and unduly intrusive" and "contrary to the expectations of investors based on the current licences on which the Gencos were sold".[52] It argues that the EMA has sufficient mechanisms available to manage market power.

In response we note the recommended 25% market capacity share cap is less restrictive than the current MW licence cap arrangements, because it allows portfolio expansion as the market grows. We note that both the current MW cap on the three largest generation businesses and our proposed 25% market capacity share cap would prohibit some potential mergers, in order to structurally limit the aggregation of market power. On balance, we continue to support a recommendation to introduce a licenced market capacity share cap for all generation businesses.

6.1.5 Hedging unvested MSSL load

Several participants comment on the requirement for the MSSL to hedge unvested MSSL load via the SGX. PacificLight Power suggest that MSSL be given the option to hedge the unvested portion either by tender or via the futures market, rather than to prescribe hedging via the futures market. Tuaspring prefers the proposal to hedge the unvested MSSL load through the exchange as opposed to tendering. RCMA suggests increased liquidity in the futures market is likely to increase the participation of Gencos in the longer term.

SP Services note the requirement to hedge unvested MSSL load is a "significant change" to their business profile.[53] SPS identify a series of factors requiring further consideration, including the market mechanism, performance obligations and risks, and the resulting customer impact. Keppel and RCMA similarly note the importance of developing a robust framework, methodology and procedures

52 Submission from YTL PowerSeraya, p5-6.

53 Submission from SP Services, p1.

to guide MSSL hedging transactions. In addition, Keppel comment on the importance of developing, in consultation with market participants, appropriate arrangements to regulate retail electricity tariffs in the future under a new regime.

Buri Energy outlines an alternative for hedging unvested MSSL load via an open tender held as a Dutch auction, and based on SGX products and cleared via the SGX. Such an approach would manage the transition of large volumes onto the market, and would allow adjustment of MSSL hedging cover via SGX trades as customers opt in and out of contestability. Buri Energy further suggest that only a new peak product is required for SGX, rather than shoulder and off-peak products which may dilute liquidity while adding little value.

In general, we broadly agree with the comments made by participants regarding our recommendation in this area. As we discuss in Section 6.4.1, hedging unvested MSSL load via the SGX is likely to promote both efficient risk management and the liquidity required to support competition in the SWEM, which acts to alleviate market power. We recognise requiring unvested MSSL load to be hedged via the SGX does represent a change to the current arrangements, and therefore transitional arrangements should enable appropriate hedging capability to be developed. We agree there may be merit in allowing some flexibility around the instruments and platforms used to hedge unvested MSSL load, as we discuss in more detail in Section 6.4.1. Once again, we recognise the merit of adding a second peak product to products traded via the SGX, which we elaborate on in Section 6.4.1.

6.2 Comments on the revised report

Submissions expanded on earlier comments on the detail of the packages presented in this section of the revised report. We consider in turn below the specific comments made.

6.2.1 Reallocation of vesting contracts

Further to comments made on the revised report (Section 6.1.2), participants commented on the recommendation to forego the reallocation of the vesting contracts in the Balanced Market package. YTL PowerSeraya expressed agreement with this recommendation, whereas SembCorp and Keppel argued for reallocation on the grounds that it would promote equity and efficiency.

The efficiency benefit associated with reallocating vesting contracts according to effective capacity primarily relates to the incentives to retire old plants or invest in new plants, i.e. dynamic efficiency. Given the lead time associated with making investment decisions we recommended the reallocation in the context of the Improved Vesting regime, which would entrench vesting contracts in perpetuity.

Under the Balanced Market regime, we consider the incremental dynamic efficiency benefit associated with reallocating vesting contracts in the period before they are reduced to LNG vesting is likely to be marginal.

Furthermore, our modelling shows that the allocation of vesting contracts has limited impact on wholesale market outcomes, and as such we do not see any market power issue related to the allocation of these contracts given they will be rolled down within two to three years. There will clearly be administrative costs associated with reallocation, and we do not see a strong rationale for these costs to be incurred on the basis of the management of market power.

6.2.2 Capacity cap

Further to comments made on the draft report (Section 6.1.4), participants commented on the recommendation to move to a 25% capacity market share cap. YTL PowerSeraya expressed concern that a 25% capacity market share cap may limit its ability to repower back to a total capacity of 3,100 MW in the future, implying a loss of currently-held optionality. Senoko expressed similar concerns and also raised the issue of the treatment of non-dispatchable capacity.

The rationale for a move to a capacity market share cap, as opposed to the current MW licensed capacity cap, was to avoid the current arrangements from becoming restrictive as the SWEM grows in future. The intention was therefore not to require forced divestments in the event that another genco's retirement of units caused the first genco's capacity market share to rise above the capacity cap. In Section 6.4.1 we clarify this intention to cover divestments of both physical assets and options to repower. We recommend that the MW capacity of all participants be restricted to the 25% capacity market share cap. As the three large Gencos are currently subject to a MW licensed capacity cap, we recommend that the MW capacity for them is restricted to the greater of the 25% capacity market share cap and the MW licensed capacity cap specified in their current generation licences. The guiding principles for implementation of this mechanism is as discussed in Section 6.4.1. We believe this addresses YTL PowerSeraya's concerns as well as the majority of Senoko's comments.

Additionally, Tuas identified a factual error with regard to its licenced capacity and MW capacity cap. This has been corrected in this report and we can confirm that the error did not influence our analysis, conclusions or recommendations.

6.2.3 Hedging of unvested MSSL load

Several submissions comment on the hedging of unvested load in response to the revised report, expanding on the comments made on this issue following the draft report (Section 6.1.5). YTL PowerSeraya comment that hedging of unvested MSSL load should not be via a tender, and that hedging unvested MSSL load via vesting or at a discount to vesting price is inconsistent with a sustainable, non-discriminatory market. Keppel comment that a robust framework, methodology and procedures need to be developed and subject to industry consultation prior to hedging unvested MSSL load. Keppel further suggest unvested MSSL load should be contracted on a bilateral basis with generators based on their CCGT capacity. In response, we agree that there is likely to be some benefit to allowing flexibility in the instruments to be used to hedge unvested MSSL load. We understand EMA will separately review and develop the hedging framework for the prudent hedging of unvested non-contestable load.

6.2.4 Price separation

Keppel commented on the issue of price separation in response to the revised report, consistent with the comments made on the draft report (Section 6.1.3). Keppel commented there is a significant negative financial impact for constrained gencos as a result of localised market power at the time of transmission constraints, and in the period until these constraints are removed constrained generators should be paid a weighted average MNN price.

While we note Keppel's comments we do not concur that there is a material issue of localised market power. This conclusion is informed by our historical analysis, our forward modelling and our understanding that major transmission constraints are likely to be built out in a timely fashion. We do however note that at times of transmission constraints there are financial implications for participants. There may be merit in considering the pricing arrangements at times of constraint as part of a wider review of congestion management beyond the scope of this review. However, we note that the EMC has recently considered a number of options in this area (RCP Paper No. EMC/RCP/85/2016/CP61).

6.3 Packages to mitigate market power in the SWEM

We have designed a series of 'packages' of market power mitigation tools, with the aim of addressing the key shortcomings of the current vesting contract regime. Each package represents an alternative approach to mitigating market power in the SWEM, and is developed by combining various features of the current regime discussed in Section 4 and the mechanisms applied in other jurisdictions identified in Section 5. Table 4 summarises the key features of each of these market power mitigation packages:

- The **status quo** refers to the current arrangements for mitigating market power in the SWEM. The key features of the current arrangements comprise:
  - the existing market monitoring and *Electricity Act* responsibilities of the EMA

- capacity caps in the generation licences of the three largest Gencos
- the current vesting contract regime, with the VCL and allocation (including scope for tendering part of the VCL) set in accordance with the EMA Procedures, incorporating our recommended VCL for 2017-18 and minor enhancements described in Section 4, and
- the ability for the EMA (on behalf of the MSSL) to hedge unvested MSSL load via a tender.

The status quo arrangements were described and assessed in Section 4 of this report, and form the base case against which each of the new packages is compared.

Table 4: Packages to mitigate market power in the SWEM

Features	Status quo	Improved vesting contracts regime	Balanced market	Combined approach
Overview	Current regime	Incremental improvements to current regime	Reduced VCL, NCC hedging offsets impact	Reduced VCL, NCC hedging & pivotal supplier test with raised MPC
Market monitoring	Maintain existing arrangements	Maintain existing arrangements	Maintain existing arrangements	Maintain existing arrangements
Capacity/ concentration cap	Maintain current capacity cap	Introduce concentration cap	Introduce concentration cap	Introduce concentration cap
Vesting level (VCL)	No change to approach, scope for gradual reduction in VCL	Set VCL via prescribed methodology (formula)	Gradually reduce VCL to LNG vesting	Gradually reduce VCL to LNG vesting
Vesting allocation	No change to approach	Gradually change to allocate based on effective capacity (CCGT + OCGT)	n/a	n/a
Hedge unvested MSSL load	Hedge via tender	Hedge via a combination of SGX, tenders and bilateral trades	Hedge via a combination of SGX, tenders and bilateral trades	Hedge via a combination of SGX, tenders and bilateral trades
Pivotal supplier test + higher MPC	n/a	n/a	n/a	Bids of pivotal suppliers capped when constraints between nodes & increased MPC

- The **improved vesting contract regime** involves incremental changes to address some of the key shortcomings associated with the status quo. Vesting contracts remain in place as the primary mechanism to mitigate the incentives for Gencos to exercise market power and existing market monitoring arrangements continue. However, the improved vesting contract regime reflects several important changes:
  - First, the capacity caps in the licences of the three largest Gencos are replaced with capacity market share caps in *all* generation licences, with a transition path for the three incumbent Gencos to prevent forced divestment.
  - Second, the current discretionary approach to setting the VCL is replaced by a more mechanistic approach that sets the VCL to achieve an adjusted HHI measure via a formula based on the Irish Directed contracts regime, to improve transparency and predictability.
  - Third, the allocation of the VCL is gradually changed to reflect Gencos' *effective capacity*, accounting for existing market positions.
  - Finally, prudently hedge the unvested MSSL load via a combination of SGX, tenders and bilateral trades.

  The improved vesting contract regime is described in more detail and assessed in Section 6.6.
- The **balanced market regime** gradually substitutes non-LNG vesting contracts with a more market-based approach to mitigating the Gencos' incentives to exercise market power. Rather than continuing to impose vesting contracts on the Gencos indefinitely, the balanced market option hedges unvested MSSL load. Vesting contracts would be gradually reduced to LNG vesting levels and then reduced to zero at the expiry of LNG vesting, with the allocation amongst the Gencos remaining unchanged during the wind-down process. Like the improved vesting regime, this package maintains the existing market monitoring arrangements and replaces the capacity caps in the three largest Genco licences with capacity market share caps in all generation licences. Section 6.5 describes and evaluates the balanced market regime.
- The **combined approach** builds on the balanced market regime, containing all the same elements as the balanced market package while adding a pivotal supplier test to manage instances of localised market power. The pivotal supplier test operates by capping the offer prices of generators found to be required to meet demand at a particular node or group of nodes, and is paired with an increased MPC to preserve resource adequacy. Like the balanced market regime, this package maintains the existing EMA market

monitoring arrangements, replaces the capacity caps in the three largest Genco licences with capacity market share caps in all generation licences, gradually phases out non-LNG vesting contracts in the short-term and LNG vesting in the future while retaining the current allocation in the interim, and prudently hedges the unvested MSSL load. The combined approach is discussed and assessed in Section 6.5.

6.4 Improved vesting contract regime

This section describes and evaluates the improved vesting contract regime, which involves incremental changes to the current arrangements for mitigating market power in the SWEM.

6.4.1 Description

The improved vesting contract regime involves making several changes to the status quo arrangements to address the shortcomings identified in Section 4. The key shortcomings identified were the issues relating to the longevity of licensed generation capacity caps, the uncertainty over the vesting contract quantities (i.e. the VCL), and the potential dynamic inefficiencies associated the current vesting contract allocation methodology.

The key elements of the improved vesting contract regime include:

- Retaining existing market monitoring and *Electricity Act* responsibilities of the EMA.
- Replacing the capacity caps in the generation licences of the three largest Gencos with capacity market share caps in all generation licences, with transitional arrangements to prevent forced divestment.
- Replacing the current methodology for setting the VCL specified in the Procedures with a mechanistic approach based on an HHI concentration model.
- Gradually adjusting the allocation of the VCL to reflect *effective* rather than licensed capacity, taking into account the existing contractual commitments of Gencos.
- Prudently hedging the unvested MSSL load. After the introduction of FRC, all remaining MSSL load, comprising those small customers that have declined to switch supplier and those customers that have returned to the MSSL as supplier of last resort, should be hedged.

Each of these characteristics is discussed in more detail below.

Market monitoring and Electricity Act provisions

As discussed in Section 4.4, the EMA has a range of responsibilities under the *Electricity Act*. In particular, section 3 obliges the EMA to protect the interests of consumers, ensure security of supply and create an economic and regulatory framework that promotes competitive, fair and efficient market conduct and prevents the misuse of monopoly or market power. The EMA is also empowered to examine conduct that may constitute an abuse of a dominant position (under section 51) and agreements, decisions or concerted actions that are intended to or will prevent, restrict or distort competition (under section 50).

We propose that these provisions be retained and that the EMA continues to investigate anti-competitive conduct or abuse of dominant positions as the EMA deems appropriate from time to time. Such investigations should help reinforce actual and prospective participants' expectations that unlawful conduct will be identified and sanctioned. This, in turn, will promote stakeholders' confidence in the integrity of the market.

Concentration cap

As discussed in Section 4.4.2, the capacity of the three largest Gencos is presently limited via an explicit licensed capacity cap in their generation licences. However, as more capacity is installed in the market, there may be a point where it is no longer justifiable to cap only the capacity of the three dominant Gencos in light of the increasing capacity of other generators.

A relatively simple alternative is to impose a capacity concentration cap that would apply to all generators, including new entrants. This broader cap would be targeted at maintaining an overall market structure that was expected to be consistent with a workably competitive market. The key question is the appropriate form and level of concentration measure that should be adopted.

We note that the US HHI measures do not apply as capacity market share caps *per se*, but rather as a factor for the relevant agency to consider when assessing the competitive implications of a proposed transaction. We also note that an Alberta-level cap of 30% on all generators in the SWEM is unlikely to have much effect, given the falling capacity shares of the original three Gencos and the still-much smaller sizes of new entrants. A lower capacity market share cap would seem to offer greater protections for competition, without intruding on smaller participants' impending plant investment decisions.

Since the introduction of Tuaspring in early 2016, the market share of the largest Genco portfolio in the SWEM (Senoko) is just below 25%. Imposing a 25% market share cap should act to ensure the SWEM does not become materially more concentrated than it is currently, consistent with the intent of current arrangements. There are also benefits as compared to the current licence cap, arising from its suitability into the longer term as the market expands and its universal applicability. Any restrictions on market concentration, including both the current licence cap and our proposed market share cap, act as complements to other market power mitigation measures to ensure that market power does not manifest in the SWEM.

Therefore, we propose a capacity market share cap of 25% in all generators' licences.

Implementing such a cap needs to consider a number of issues. Importantly, we would stipulate that a Genco would not violate its existing licensed capacity cap simply because another generator retired one of its existing plant, even though this may increase the first Genco's capacity market share above 25%. Similarly, under the current generation licence, the largest three Gencos currently hold options to repower at some future date up to their existing licensed capacity cap. Consistent with the principle of no forced divestments, we recommend that the MW capacity of the three large Gencos be restricted to the greater of the 25% capacity market share cap and their respective MW licensed capacity cap under their current generation licences.

To implement the above, our recommendation is that the key features include:

- A universally applied 'set and forget' capacity market share cap set at 25%.
- Implementation that ensures Gencos are not forced to divest physical assets or currently held opportunities to expand or acquire under their current generation licences.
- That the implementation not place obligations to repower units contingent on their retirement. We would be concerned if the implementation of the capacity cap altered participant incentives to repower with regard to timing or size beyond the basic constraint implied by the cap as an upper bound.
- That, in the case of mergers, any right to current licensed capacity cap should not be additive across the acquirer and target assets.

In our view, imposing our recommended concentration cap would maintain the structure of the SWEM consistent with that of a workably competitive market.

Design parameter 2 – Generation concentration cap

We recommend a capacity market share cap of 25% that is implemented to ensure no forced divestment of physical capacity or currently held options to repower under the current generation licences.

Vesting Contract Level

Rather than the EMA balancing the current list of factors in setting the VCL, an alternative approach would be to set the VCL using a formulaic approach against a target adjusted HHI measure, based on the Irish 'Directed Contracts' regime. This would be consistent with the policy objective of the vesting contracts regime to mitigate incentives for the exercise of market power.

Under this package, the VCL would be set with a view to achieving an appropriately low 'vested HHI' (being the HHI obtained when subtracting vested generation capacity from the Gencos' market shares – see example below).[54]

A hypothetical example

Table 5 presents a hypothetical example of how to calculate a 'vested HHI'. For simplicity, we assume the following:

- that the market comprises only seven hypothetical Gencos, i.e. there are no other participants
- there are no LNG vesting contracts
- we consider a total vesting contract quantity allocated on the basis of capacity market share
- we assume an average load of 5,600 MW.

We see firstly that the 'raw HHI' is a value of 1,609, comparable to the actual SWEM HHI of 1,549 despite assuming there are only seven players in the market.

Secondly, we see that as VCL rises from 17% to 25%, the 'vested HHI' falls from 1,437 to 1,360. This is consistent with the assumption that capacity under vesting contracts is perfectly competitive.

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54 'Vested' in the SWEM context would need to exclude both regular vesting contracts as well as LNG vesting contracts.

Table 5: Hypothetical example of vested HHI

Portfolio	Capacity (MW)	Capacity market share	Vested market share VCL 17%	Vested market share VCL 20%	Vested market share VCL 25%
Portfolio A	2,900	16.8%	15.8%	15.7%	15.4%
Portfolio B	2,200	12.7%	12.0%	11.9%	11.7%
Portfolio C	1,500	8.7%	8.2%	8.1%	8.0%
Portfolio D	4,400	25.4%	24.0%	23.8%	23.4%
Portfolio E	1,900	11.0%	10.4%	10.3%	10.1%
Portfolio F	2,300	13.3%	12.6%	12.4%	12.2%
Portfolio G	2,100	12.1%	11.5%	11.4%	11.2%
HHI (raw and vested)		1,609	1,437	1,408	1,360

Note: This example is for a hypothetical system, ignores the LNG Vesting contracts whilst assuming an average load of 5,600 MW and that vesting contracts are allocated on the basis of capacity market share.

Using a prescribed method to set VCL via a 'vested HHI' threshold requires reversing the example above. Instead of calculating the 'vested HHI' as a function of VCL, rather we infer a VCL for a given 'vested HHI' threshold. Building on the example in Table 5, we can infer VCL for a range of threshold values as shown in Table 6.

Table 6: Hypothetical threshold example

Threshold	Implied VCL
1800	0%
1500	11%
1200	42%

Note: This example is for a hypothetical system, ignores the LNG Vesting contracts whilst assuming an average load of 5,600 MW and that vesting contracts are allocated on the basis of capacity market share.

The example above demonstrates that, to some extent, the threshold must be set relative to the idiosyncratic market structure of the wholesale market under consideration.

Setting the threshold

The question is what vested HHI threshold should be the threshold for determining the VCL. The vested HHI is a somewhat artificial concept, as it assumes vested capacity contributes zero to the concentration index. Given this, there are two broad approaches to setting a threshold:

- Calibrating the threshold to an initial vesting contract level that is deemed to be optimal. This is essentially the approach pursued (successfully) in Ireland, which has adopted a threshold of 1,150.
- Using an independent threshold based on standard interpretations of HHI values. Whilst a 'raw' HHI and the vested HHI as calculated above are not directly comparable, there are reasonable grounds for targeting an objective concentration index level to the extent that structural separation of generating units can be considered broadly comparable to the impact of allocating vesting contracts to some proportion of a generator's capacity.

In either case, the initial vesting contract level would only change to the extent that generation entry, exit or merger occurred *or* if the threshold was changed at some later date.

We prefer the objective threshold approach and consider that the most credible objective threshold is to target an HHI consistent with an unconcentrated market.

In light of these considerations, we propose that the VCL be set to achieve a vested HHI of 1,250, this being mid-way between the thresholds that the FERC and DoJ/FTC regard as needed for an unconcentrated market. This threshold would be applied consistent with the example in Box 1. We note that an HHI of 1,250 would be consistent with a VCL of 17% (see Figure 27), which is well below the current value of 25%.

Once determined, the volume of vesting contracts would be varied on an annual or biennial basis so as to maintain the vested HHI at the target level, within a tolerance of 50 points to avoid unnecessary changes in the VCL for small changes in the HHI. Over time, to the extent that new entrant or small generator-owned capacity entered the market and lowered the vested HHI, the implied VCL would fall. Conversely, mergers or plant exit would raise the implied VCL.

The only other factor that could lead to a change in VCL is if the threshold itself was altered at some future date. Locking the threshold into perpetuity would maximise the predictability of the arrangements, at the expense of some further loss of flexibility. We would recommend committing to a long dated periodic review of the threshold, for example every 5-8 years.

Moving to a prescribed approach for setting VCL as outlined above would greatly increase the transparency and predictability of the vesting arrangements.

However it is worth noting that adopting such an approach would lock in the wider vesting contracts regime into the longer term, potentially making the vesting contracts a permanent feature of the SWEM. This outcome may be contrary to wider policy objectives.

Design parameter 3 – Prescribed, vested HHI approach for setting VCL

We recommend setting the VCL based on a prescribed, formulaic methodology whereby the VCL would be set with a view to achieving an appropriately low 'vested HHI'.

We propose that the VCL be set to achieve a vested HHI of 1,250, and reviewed periodically.

Vesting contract allocation

As discussed in Section 4.3.8, the current approach to allocating vesting contracts amongst the Gencos based on their individual share of the sum of their historically licensed or planned generation capacities that are still in operation. A key drawback of this approach to contract allocation is that it can discourage Gencos from retiring their older inefficient plants (such as steam plants). Further, given the transitory nature of most high price events in the SWEM, most steam plants would not be able to influence market outcomes (given 24-48 hour response times); allocating vesting contracts on the basis of plant capacities that are effectively not part of the market within realistic response times is likely to reduce the impact of such contracts on mitigating market power.

To address this shortcoming, we propose revising the vesting contract allocation approach to base the allocation on *effective capacity* – where effective capacity refers to the sum of Gencos' licensed CCGT and OCGT plant capacities only and where the existing generators (including Tuaspring) and any future new entrants with effective capacity are included in the allocation.

In addition, we propose capping (in MW volume terms) the allocation of contracts to smaller Gencos (currently the Jurong Island-based Gencos) to ensure those Gencos do not become over-hedged with regard to the sum of the allocated vesting position plus any retail load the Genco may have relative to their respective capacity. Market share for the purpose of allocating vesting would then be determined as the share of these effective capacities.

We have modelled a range of allocations against a VCL of 17%:

- the current allocation method of total capacity
- an allocation based on effective capacity capped as described above
- an allocation based on effective capacity not capped and
- an allocation based on minimising the HHI.

Modelling under the wider base case assumptions (see Figure 28) indicates that there is no material difference in price outcomes between any of these methods of vesting contract allocation. Therefore, we propose adopting an allocation approach that recognises physical plant limitations while minimising radical contract reallocations that could undermine the stability and predictability of the vesting contracts regime.

> ***Design parameter 4 – Vesting contract allocation***
>
> Vesting contracts should be allocated on the basis of the Gencos' *effective capacity* – where effective capacity refers to capacity that can respond to short term price events and currently equates to CCGT and OCGT plant capacities only. Allocations should be made to any effective capacity belonging to existing generators and any future new entrants.

Hedging unvested MSSL load

In our draft report we suggested a key element of this package is the obligation on the MSSL to hedge any unvested MSSL load via contracts to be primarily purchased on the SGX – subject to certain preconditions being met (see below). This differed from our recommendations regarding the VCL for 2017-18 under the status quo (see Section 4), which focus on ensuring the MSSL load is prudently hedged, using the current EMA tendering mechanism under the vesting contract procedures. While we continue to support the benefits of hedging via SGX contracts, on balance we support participant comments that a particular hedging strategy should not be mandated. We discuss this in more detail below.

There are two key benefits of shifting from an EMA tender approach to hedging unvested MSSL load to hedging via the SGX:

- First, hedging via the SGX occurs on a continuous basis against a background of general trade and is intermediated by the exchange rather than involving *ad hoc* tenders that are directly linked to reductions in the VCL. We believe this will be a more sustainable approach for hedging unvested MSSL load, because exchange traded products result in significantly lower search costs, compared to the alternative of hedging via tenders or other bilateral arrangements. In addition, the anonymous nature of trade on an exchange is likely to reduce barriers to trading financial products in the SWEM. These benefits are likely to be magnified as the volume of MSSL load to be hedged increases, as a result of reductions in the VCL.
- Second, over time, a shift to SGX hedging should enhance the liquidity of the SGX. This would encourage potential new entrants on both the generation and retail sides of the market to enter. This is because potential entrants

would have greater confidence in access to a liquid SGX that could provide competitively-priced hedging instruments to mitigate the financial risks of entering on one side of the market only. In addition, more liquid trade on the exchange is likely to attract financial intermediaries, further deepening liquidity. Further, both the MSSL and its ultimate counterparties (via the SGX) would be able to adjust their positions more easily than if they had engaged in a tender. This is because all trade on the exchange would occur using common contracts, compared to the bespoke terms associated with the tenders. This would facilitate the allocation of financial risks to those best placed and most willing to manage it.

At the same time, we recognise requiring the unvested MSSL load to be hedged via the SGX would raise a number of implementation challenges. For example, historically MSSL load has been hedged via vesting and tender arrangements, and the required trading systems, procedures and capacity required to hedge unvested MSSL load via the SGX need to be developed.

Similarly, there is currently only a single flat swap product offered on SGX and turnover and liquidity are still developing in the market. In other jurisdictions it has taken some time to see the full development of deep and liquid contracting markets, however once established such markets typically become the primary means of risk management. We expect a similar outcome in the SWEM in the fullness of time given the current trajectory of liberalisation.

Therefore, we recommend hedging the unvested MSSL load primarily using the futures market should be viewed as an end point that is likely to be achieved via a number of intermediate steps as follows:

- Establishing appropriate trading capabilities and incentives, including trading and risk management policies, platforms, and expertise.
- Encouraging the development of an additional exchange traded product to allow hedging of the shape of the MSSL load. Based on the feedback received on our draft we suggest that the development of a second product should be a secondary objective once sufficient liquidity and turnover of the existing flat swap product has been demonstrated.

We now consider the issue of the most appropriate second product to be offered on the SGX, drawing on Buri Energy's comments. The obvious candidate for a second product is a peak swap product, consistent with product development in most wholesale contract markets. However we note that, given that the MSSL load reaches its maximum level during off-peak periods, an alternative product type may be more appropriate in the SWEM. Generating offpeak cover to hedge unvested MSSL load would therefore require an offpeak product via the combination of a flat product purchase and peak product sale (leaving it with an effective offpeak purchase).

This raises the question of who would buy the SGX peak product offered for sale. Whilst independent retailers would likely represent significant demand for a peak products in the longer term, this may impose an initial barrier to hedging the unvested MSSL load via the exchange. A cap product may be attractive to a larger number of participants – for hedging the unvested MSSL load, meeting the requirements of independent retailers and also for Gencos selling cover – whilst minimising initial complexity. We would therefore suggest that some form of cap product should be considered as a candidate for the second exchange traded product (assuming that a peak swap product is already viewed as an option). Such a cap product could be based on a fixed strike price or a variable strike price linked to oil prices.

Rather than requiring all MSSL load to be hedged exclusively via the SGX, we recommend futures contracts could be used as part of a portfolio of products to hedge unvested MSSL load. Notwithstanding the benefits of hedging MSSL load via the SGX, mandating the use of one risk management product may frustrate effective risk management and the cost effective management of MSSL load.

Given that a number of the arrangements outlined above (or alternatives) may take some time to implement, we note that this transitional hedging of the unvested MSSL load could occur via an EMA tender process, or a combination of SGX, tenders and bilateral trades.

We therefore recommend SGX be used as part of a portfolio of products to hedge unvested MSSL load. In mature electricity markets around the world exchange based trading dominates the risk management instruments used by most market participants. We similarly expect that as the financial market in Singapore matures, trading via the SGX is likely to become more common and be used to hedge a larger part of unvested MSSL load, without the necessity of mandating this arrangement.

We understand the EMA will separately review and develop the regulatory framework for hedging unvested MSSL load, consulting the industry where appropriate.

Design parameter 5 – Hedging unvested MSSL load

Unvested MSSL load should be prudently hedged. Such hedging could be via a combination of available SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

Minor enhancements

We would also suggest that the minor enhancements proposed for the Status Quo package as part of Design Parameter 1 should be included in the Improved Vesting Contract package.

6.4.2 Assessment

Effectiveness

The improved vesting contract package is likely to be slightly more effective in mitigating market power than the status quo arrangements for two main reasons. First, the proposed capacity market share caps should better ensure that the market structure is compatible with a workably competitive market into the future than the current capacity caps. Second, the allocation of vesting contracts on effective capacity rather than historical registered and planned capacity should better target the allocation of vesting contracts to those parties with a greater ability to cause price spikes.

Dispatch efficiency

For the same reasons as the effectiveness of this package represents a slight improvement over the status quo, this package could slightly improve the economic efficiency of generator dispatch in the SWEM.

Resource adequacy

Due to the improved incentives for retiring inefficient plant, and potentially replacing them with more efficient and/or flexible plant, this package should offer a small improvement in resource adequacy in the SWEM.

Intrusiveness and administrative burden

The improved vesting contract package is roughly as intrusive and administratively burdensome as the status quo vesting contracts regime. Like the status quo arrangements, the improved vesting regime allows for hedging of unvested MSSL load via a voluntary mechanism, with that mechanism being MSSL swap purchases through the SGX in this package. However, the improved vesting contract regime entrenches vesting contracts as a permanent feature of the SWEM, rather than a temporary tool used to manage market power.

Transparency and predictability

The improved vesting contract package offers some demonstrable improvements in the transparency and predictability of the vesting contract regime relative to the status quo arrangements. The key improvement in this package is the greater clarity around the criteria that drives the VCL. Rather than having the determination of the VCL based on a wide range of potentially divergent factors, the improved vesting contract package narrows the criteria for setting the VCL down to what is necessary to achieve a target vested HHI (proposed to be 1,250). This formulaic approach to calculating the VCL would enable market participants to replicate the calculations under various scenarios, reducing the uncertainty associated with the periodic VCL reviews under the status quo.

6.5 Balanced market

This section describes and assesses the balanced market regime, which is the simplest of the alternatives considered.

6.5.1 Description

The balanced market regime involves phasing out vesting contracts and relying on voluntarily-entered swap contracts to manage market power, supported by the requirement for the MSSL to prudently hedge the MSSL load. Compared to the alternatives, the balanced market approach is a relatively 'hands-off' approach to managing market power in the SWEM.

The key characteristics of the balanced market regime include:

- Retaining the EMA's existing market monitoring and *Electricity Act* responsibilities.
- Replacing the capacity caps in the generation licences of the three largest Gencos by a 25% market share cap in all generation licences.[55]
- Prudently hedging unvested MSSL load.
- Phasing out vesting contracts.

Each of these characteristics is discussed in more detail below. The first of these three characteristics is identical to that proposed for the improved vesting contracts regime, and therefore design parameters 2 and 5 apply to this package as well.

Market monitoring arrangements

As for the improved vesting contract package, the existing market monitoring arrangements would remain in place to manage the exercise of market power that constitutes an abuse of a dominant position.

Concentration cap

As for the improved vesting contracts regime, the balanced market regime involves replacing the existing capacity caps included in the generation licences

55 Consistent with Design Parameter 2.

for the three largest Gencos with a concentration cap, via a transition path that avoids forced divestment.

Vesting contract level and allocation

Under the balanced market regime, vesting contracts will be phased out in two key stages:

- Balance vesting quantities will be gradually reduced to zero over a defined period, say two to three years.
- LNG vesting quantities will remain in place until 2023. A systematic approach to hedging MSSL load should be considered in anticipation of the expiry of LNG vesting to minimise the potential market disruption associated with the expiry of LNG vesting.
- Notwithstanding the inefficiencies associated with the current vesting contract allocation methodology, the VCL would continue to be allocated based on licensed capacity consistent with the status quo. Balance vesting quantities will be relatively limited and declining over the period until they are phased out under the balanced market approach. The relatively small volumes and finite period concerned means reallocating balance vesting quantities between generators on the basis of effective capacity is likely to be disruptive and deliver marginal benefit in this case. This is contrast to the longer term benefits of reallocating vesting contracts given their longevity under the improved vesting regime.

Design parameter 6 – Phase out vesting contracts

Vesting contracts should be phased out under the balanced market approach in two key stages. First, balance vesting quantities should be reduced to zero over a defined period, say two to three years. Second, LNG vesting will be set to zero once the vesting contracts expire. Vesting contract allocation should remain unchanged over this period.

Hedging MSSL load

As for the improved vesting contract regime, the balanced market regime would impose a requirement that unvested MSSL load should be prudently hedged. Such hedging could be via a combination of available SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

Minor enhancements

We would also suggest that the minor enhancement regarding gradual adjustment of vesting quantities proposed for the Status Quo package as part of Design

Parameter 1 would be appropriate for consideration in the Balanced Market package. Specifically, quarterly VCL adjustment would align with the availability of the SGX futures contract products as recommended under the set of preconditions. Given the intention to wind down VCL in this package, there would be no requirement for a VCL cap.

6.5.2 Assessment

Effectiveness

While LNG vesting contracts will remain in place under the balanced market regime until their expiry, the primary mechanism for managing market power in this package is to completely hedge MSSL load. In the period to FRC, this obligation will ensure a minimum level of contract cover in the SWEM equivalent to MSSL load, currently around 29%. As the analysis presented in Section 4.5 and Appendix E: Setting the VCL for 2017 and 2018 demonstrates, prudently hedging MSSL load is as effective in mitigating market power as the current vesting contracts under our base case assumptions. Phasing out vesting contracts, and relying on the complete hedging of MSSL load to mitigate market power, is therefore likely to be effective.

Once FRC is introduced, it is likely that the level of MSSL load to be hedged by the MSSL will fall, as customers choose to migrate to other electricity retailers. It is reasonable to assume that, consistent with current practice in the SWEM and wholesale electricity markets internationally, retailers competing to supply small customers will hedge that load, either directly through bilateral contracts and exchange traded contracts, or via a natural hedge with generation capacity. In this case, the aggregate level of contract cover across the market will act as a discipline to drive competitive outcomes.

While vesting contracts are allocated between Gencos according to a defined set of rules, the allocation of contracts under the balanced market regime will be market-based and dynamic. The allocation of contracts between participants via the SGX will depend on a range of factors, including their available capacity, trading strategy, market position, risk appetite, and their fuel and other contractual obligations. These variables are likely to result in the allocation of SGX contracts differing from the vesting allocation to some extent. However, our market modelling indicates that different allocations of unvested MSSL load across the Gencos result in very little change to market outcomes (see Figure 29), even when SGX contracts are assumed to be allocated in a manner that maximises the HHI (i.e. in a manner *least favourable* to mitigating market power).

The balanced market regime is unlikely to be effective in addressing instances of localised market power arising at a node or group of nodes due to the presence of transmission constraints. Under the status quo, vesting contracts are settled against the weighted-average nodal price for each Genco, reducing the incentives for Gencos to exercise market power during localised events. However, the SGX traded contracts under the balanced market regime would be settled at USEP. Under these arrangements, Gencos that earn a weighted-average price greater than USEP as a result of a price separation relating to a transmission constraint would get to keep that benefit, and therefore continue to face incentives to exercise localised market power.

Our analysis presented in Section 4.5 and explained in more detail in Appendix E: Setting the VCL for 2017 and 2018, demonstrates that while the probability of high-price events increases at relatively low levels of contract cover, average price outcomes remain consistent with a competitive market. The balanced market regime is therefore likely to be effective in mitigating market power in the SWEM.

Dispatch efficiency

Due to its efficiency in mitigating the exercise of market power, the balanced market approach is similarly likely to promote dispatch efficiency.

Resource adequacy

The market-based approach of the balanced market regime is likely to facilitate resource adequacy from several perspectives. First, the market-based allocation of contracts via the SGX will remove the incentives for Gencos to maintain licensed capacity to attract vesting revenue under the status quo. This should facilitate the efficient retirement of steam plant to attract new investments on a timely basis. Second, increasing the liquidity and product base of the SGX is likely to facilitate ease of entry for a range of market participants, including new entrant retailers and financial intermediaries, establishing the foundation for the successful introduction of FRC. Finally, reducing the extent of regulatory intervention in the market will provide clear signals about the value of generation investments in the future.

Intrusiveness and administrative burden

The market-based approach to managing market power under the balanced market regime means minimal regulatory intrusion for market participants. There will be compliance costs associated with ensuring the MSSL load is completely hedged. However, these costs are likely to be relatively limited compared to the alternative of administering vesting contracts under the status quo. The administrative burden associated with LNG vesting contracts will continue until the expiry of these contracts, limiting any improvement to the reduction in balance vesting. In the longer term, the removal of the EMA Procedures may reduce the intrusiveness and administrative burden of this package by limiting the scope for intervention in the SWEM in the future. Accordingly, the balanced market regime is likely to be less intrusive and impose a smaller administrative burden than the status quo.

Transparency and predictability

The exchange-based approach of the balanced market package facilitates transparency. The traded volumes and prices of various types of contracts are published and made available to market participants in summary form on a daily basis. Information about the proposed transition from vesting contracts to hedging MSSL load via the SGX can be published to ensure transparency and facilitate predictability.

Additionally, transparency and predictability are likely to be enhanced by removing the Procedures, limiting the scope for intervention to achieve other policy objectives using the vesting regime in the future.

6.6 Combined approach

The combined approach builds on the balanced market regime, by adding a pivotal supplier test to address localised market power.

6.6.1 Description

The combined approach, like the balanced market package, involves phasing out vesting contracts and relying on voluntarily-entered swap contracts supported by the requirement for the MSSL to prudently hedge the unvested MSSL load to mitigate market power. However, the combined approach extends beyond the balanced market package to include a pivotal supplier test, which limits localised market power by capping key generators' offers at times of binding transmission constraints. Given that the pivotal supplier test has the potential to limit high prices in the market, it is paired with an increase in the MPC to assist participants to recover their efficient costs and help promote resource adequacy.

The key elements of the combined approach include:

- Retaining the EMA's existing market monitoring and *Electricity Act* responsibilities.

- Replacing the capacity caps in the generation licences of the three largest Gencos by a 25% market share cap in all generation licences.[56]
- Phasing out vesting contracts.
- Prudently hedging unvested MSSL load.
- Introducing a pivotal supplier test, which acts to cap key generators' offers at times of binding import constraints to a particular node or group of nodes.
- Raising the MPC.

The first four of these elements is identical to those applying in balanced market package discussed in Section 6.5.1 and accordingly design parameters 1, 2, 5, and 6 apply. The pivotal supplier test and MPC are discussed in more detail below, following a brief description of the approaches to managing congestion in wholesale electricity markets.

Managing congestion in wholesale electricity markets

We have found that price separation arising from transmission congestion has not been a frequent occurrence in the SWEM, nor is it likely to become a material problem in the future as constraints will typically be alleviated via transmission investment in a timely fashion. We do not see evidence of the systemic exertion of localised market power by any participants, historically or on a forward modelling basis. Whilst we have considered the ability of a pivotal supplier test to mitigate any future localised market power, we have not reviewed alternative pricing approaches for the market more generally. We would note that the core issue is transmission congestion which currently manifests as price basis risk for the Gencos.

Congestion management is a different issue to the management of market power, localised or otherwise, and beyond the scope of our engagement. Congestion can be managed, but as long as transmission constraints arise in an electricity market, the effect will be felt in one form or another. Given the lumpy and capital intensive nature of transmission assets, in practice it is not economically efficient to design an electricity network such that no congestion ever arises as this would involve costly redundant infrastructure. This implies that congestion will always be an issue to some extent in any electricity market.

56 Consistent with Design Parameter 2.

Under a nodally priced market, generators on the exporting side of a binding constraint experience price separation. Local dispatch in the exporting region reflects local market offers, which are less than market prices on the importing side of the constraint. If the generator needs to purchase energy at higher prices (e.g. USEP) to meet retail obligations this creates a gap between the (lower) prices received for dispatch and the (higher) prices paid to supply retail load.

Altering market outcomes or rules – via a PST, change to pricing rules or otherwise – does not remedy the underlying congestion issue.

Under a PST within a nodally priced market, price separation may be mitigated to the extent that it is caused or exacerbated by the exertion of localised market power. However, price separation would certainly not be eliminated by the introduction of a PST except in the case where all transmission constraint was driven by the exertion of market power.

Under a uniformly priced market, generators on the exporting side of a binding constraint experience dispatch risk. Offers from these export constrained generators cannot influence the uniform market price (which is set in the importing region for the whole market). This creates incentives for generators to maximise dispatch behind the constraint at the higher (uniform) market price. In practice, generators may have incentives to 'disorderly bid' by offering capacity at negative prices or even the market price floor in order to maximise dispatch relative to their competitors behind the constraint. Resolution of dispatch under these conditions usually requires the market clearing engine to include a tiebreaker rule that prorates the binding export limit across the dispatch of the constrained generators such that a generator is "constrained off" (not fully dispatched for some of all offers even though those offers are at prices less than the extant uniform market price). This means that while the generators no longer experience a gap in prices, they now may experience a gap in volumes, i.e. in their level of dispatch relative to the level of retail load they carry. Fundamentally, they are still exposed to a differential between the revenue they receive for dispatch and the cost they incur purchasing load.

Issues of congestion management have typically be the subject of extensive reviews in and of themselves, for example in Australia the Australian Energy Market Commission has looked at the issue on a number of occasions.[57]

Pivotal supplier test

A pivotal supplier test is a real-time test applied in the market dispatch engine. The test seeks to identify those generator(s) whose available capacity is required to meet demand (i.e. the generator is 'pivotal') within a part of the network under conditions of constrained imports to that part of the network. If a generator is found to be pivotal in a given initial dispatch, then alterations are made to the generator's bids and the market is re-dispatched in real time.

Pivotal supplier tests are applied in a variety of forms across a range of markets including PJM, ERCOT (Texas), and New Zealand (in applying the safe harbour provisions).

A pivotal supplier test applied in the SWEM could test the demand and supply conditions around any constrained importing node or group of nodes to identify whether any generator's available capacity was needed to serve load in that area. For example, if there was an import constraint into the mainland from Jurong Island, all of the generators in mainland Singapore would be subject to the pivotal supplier test.

The test would calculate whether the load behind the constraint could be met by imports plus the sum of all *other* suppliers' maximum availability. To pass the test, supplier 'i' must satisfy the following requirement:

$$Constrained\ Imports + \left(\sum_{j=1}^{n} Max\ Availability_j\right) - Max\ Availability_i \geq Local\ Load$$

In the event that supplier i does not satisfy this condition, it is deemed to be pivotal.

Once a pivotal supplier has been identified, the bids of that supplier can be changed, either by capping offer prices and/or imposing minimum generation constraints. Imposing minimum generation constraints is problematic in practice,

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57 See for example the 2006 Congestion Management Review and the 2011 Transmission Frameworks Review.

See weblinks: http://www.aemc.gov.au/Markets-Reviews-Advice/Congestion-Management-Review and http://www.aemc.gov.au/Markets-Reviews-Advice/Transmission-Frameworks-Review.

as it is difficult to differentiate between legitimate forced outages and physical withdrawal strategies. Moreover, imposing minimum generation constraints may reduce the economic efficiency of dispatch, as a number of technical and operating constraints would need to be accounted for. Accordingly, we recommend avoiding imposing minimum generation constraints, and instead capping the offers of pivotal generators. The risk of this approach is that pivotal suppliers may attempt to circumvent the objective of offer caps by physically withdrawing capacity to influence market outcomes.

Fundamentally, it will always be difficult for the EMA to distinguish between a legitimate forced outage event and physical withholding given the inherent information asymmetry between the EMA and the Gencos. However, as the pivotal supplier test will apply on a trading-interval-by-trading interval basis, it would be difficult to 'fake' a forced outage without forgoing extensive dispatch and revenue opportunities. The choice between applying either bids caps or minimum generation obligations on Gencos involves different risks for the relevant Genco and the market. When considering a pivotal Genco who may be either suffering a forced outage or physically withholding capacity, the outcomes could be as follows:

1. **Forced outage, minimum generation obligation imposed:** this may lead to a Genco being directed to operate at a level it cannot meet, and potentially facing penalties for non-compliance.
2. **Forced outage, offered quantities are bid-capped:** this allows for the desired outcome, as the Genco is suffering a legitimate forced outage and prices should rise to reflect scarcity.
3. **Physical withholding, minimum generation obligation imposed:** this is the desired outcome, as the Genco's attempt to exert market power is frustrated.
4. **Physical withholding, offered quantities are bid capped:** the pivotal Genco may still be able to exercise market power.

Outcomes two and three are economically efficient outcomes involving no further issue. Outcomes one and four are problematic. In our view the issues raised by outcome one are potentially more damaging to the market than outcome four. Furthermore, outcome four can be managed through a combination of the EMA's current monitoring and the application of the pivotal supplier test on a trading interval basis (limiting the ability to game the test). Finally, a regime of penalty payments could be developed to supplement existing provisions and further ensure pivotal suppliers face strong incentives to continue to offer their physically available capacity for dispatch, although a well implemented pivotal supplier test should obviate the need for any penalty regime.

The level at which the offers of pivotal suppliers are capped has important implications for dispatch efficiency and potentially resource adequacy. It is important that generator offers are capped at a level no less than their SRMC, in order to avoid generators being dispatched at prices below their avoidable costs of generating. If this occurred, it could potentially result in out-of-merit order (i.e. inefficient) dispatch. If there was a serious risk of offers being capped at less than a generator's SRMC, the market design would need to be modified to incorporate a compensation scheme whereby generators could recover their shortfall operating costs. Such a scheme would be resource-intensive and administratively burdensome to operate, and thus ought to be avoided if possible. In addition, other things being equal, the lower the level at which pivotal generators' offers were capped, the higher the MPC would need to be to enable efficient plant to recover their fixed costs.

Capping the offers of pivotal suppliers at a notional level expected to be comfortably above SRMC would ensure generators' avoidable costs were always covered, thereby removing the need for compensation. For example, offers could be capped at a level reflecting the SRMC of an OCGT with its fuel costs doubled (currently equivalent to $350/MWh). An increase in the MPC from its current level of S$4,500/MWh, as discussed below, would further promote resource adequacy.

Once the pivotal generator(s)'s offer prices are capped, the market is re-dispatched in real time to determine the revised dispatch schedule. The application of the pivotal supplier test on a trading interval basis ensures Gencos are not able to manipulate the arrangements by bidding to trigger the pivotal supplier test and simultaneously withdrawing capacity within a given trading interval. Appendix E: Pivotal supplier test presents several worked examples that illustrate the application of a dynamic pivotal supplier test in the SWEM.

Design parameter 7 – Pivotal supplier test (PST)

A dynamic PST should be applied in the combined approach to identify suppliers that are required to meet demand in any import-constrained subnetwork (i.e. are pivotal) arising from transmission constraints. The bids of pivotal suppliers should be capped at a representative level, for example $350/MWh, representing an OCGT plant's SRMC with doubled fuel costs, to ensure participants are able to recover their variable costs. The PST should be designed to minimise any gaming and to remove incentives to physically withdraw capacity, which can primarily be achieved via implementing the test on a trading interval basis.

Market price cap

Finally, although it is not an element of the current vesting regime and hence is beyond the scope of our review, we hold some concerns regarding the sufficiency of the current SWEM market price cap (MPC) of S$4,500/MWh in relation to encouraging the market to provide resource adequacy in the long term. System planning in the SWEM is currently based on a minimum reserve plant margin of 30%. This is intended to cater to scheduled maintenance as well as forced plant outages and is based on a loss of load probability of three days per year.[58]

Drawing on some stylised assumptions, the implications of the SWEM reserve plant margin, peaker fixed costs and ability to earn positive operating profits outside of load shedding periods, it appears unlikely that a MPC of S$4,500/MWh would enable efficient marginal peaking plant to recover their fixed costs (see Table 12 in Appendix E – Quantitative analysis results).

The relevance of these observations to the current Review is that any measure that is likely to be *even more effective* in mitigating the exercise of market power than the current vesting regime will only increase the need for the MPC to be revisited and potentially raised. The introduction of a PST has the potential to undermine the energy-only structure of the SWEM to some extent by reducing the frequency and extent of high price events related to transmission constraints. It seems likely that the efficacy of a PST in limiting high price events would increase during times of increased transmission congestion and/or tighter supply-demand conditions, arguably muting signals to investors and harming resource adequacy.

Particularly if the PST were to be introduced, we suggest that the EMA should commission an independent review of the appropriate level of the MPC against a number of criteria, including the importance of providing incentives for resource adequacy while minimising incentives to exercise market power.

Design parameter 8 – Review of the Market Price Cap

Review the appropriate level of the MPC to enhance resource adequacy with reference to the market power mitigation measures adopted or to be adopted in the SWEM.

6.6.2 Assessment

Effectiveness

The combined market package includes many of the same elements as the balanced market regime, and is therefore likely to be as effective in mitigating

58 See EMA website at: https://www.ema.gov.sg/System_Planning.aspx (accessed 18 April 2016).

market power across the market. In particular, the workable competition prevailing in the wholesale market in combination with the requirement to hedge unvested MSSL load is likely to be as effective in mitigating market power as vesting contracts.

The addition of a pivotal supplier test under the combined approach means that the combined approach is likely to be more effective than the balanced market approach in mitigating instances of localised market power. The pivotal supplier test would act to cap the bids of pivotal suppliers, constraining the exercise of localised market power by generators located in parts of the network experiencing import constraints.

However, it is not clear that instances of localised market power are a significant issue in the SWEM. As the discussion in Section 6.6.1 and Appendix E: Pivotal supplier test demonstrates, a pivotal supplier test is only likely to be applied under a relatively specific set of circumstances. Our analysis of historical data indicates that a pivotal supplier test would have applied only rarely over the period 2009-2012, and less than 0.8% of the time in 2013 and 2014. A pivotal supplier test may have applied just over 1% of the time in 2015, due to some exceptional circumstances relating to generation outages and other non-normal system factors in July and October (see Figure 32). Further, assuming a pivotal supplier test would apply during these periods, the annual impacts on USEP are relatively minor. Our market modelling of future periods indicates a pivotal supplier test would be unlikely to trigger under system normal events. Indeed, examples presented in Appendix E: Pivotal supplier test shed light on why this is the case, as rather extreme system events must take place in order for (1) the test to be triggered in the first place and (2) for any supplier to actually be capped.

Moreover, we understand that investment to increase the capacity of transmission lines between Jurong Island and the mainland will be commissioned in mid-2018, reducing the incidence of the most frequently binding constraint in the SWEM.

To the extent that highly-specific circumstances arise in future that would cause the pivotal supply test to be triggered, there may be some benefit from the introduction of such a test at that time. However, this benefit would need to be considered against the significant costs associated with developing and implementing the arrangements, and the wider risks to the investment environment from further intervening in the market. We would note that our market modelling necessarily incorporates a simplified representation of the SWEM's transmission network. As part of the development and design of any pivotal supplier test, we recommend that more detailed market modelling be undertaken to test if, and under what set of circumstances, a pivotal supplier test would be likely to trigger in future periods in the SWEM.

At a minimum, this should involve detailed load flow modelling of the transmission network to establish the likely extent of future transmission congestion in the SWEM over at least a 5 year time frame under both system normal and non-normal conditions. Ideally, such analysis would further involve wholesale market modelling that expanded on the regional representation of the market used in this Review to include a full set of transmission security constraints.[59]

Design parameter 9 – Analysis of pivotal supplier test (PST)

To the extent that future circumstances in the SWEM exacerbate transmission congestion, further analysis regarding the appropriateness of a PST to manage localised market power should be undertaken at that time. This would include load flow modelling to establish the extent to which transmission congestion is likely to occur in the SWEM and, ideally, further wholesale modelling with a more complete representation of the transmission system should then be undertaken to quantify the impact of a PST.

Dispatch efficiency

As with the balanced market package, the market-based allocation of contracts associated with the full hedging of MSSL load is likely to facilitate efficient dispatch. The introduction of a pivotal supplier test as outlined in Section 6.6.1, with bids capped well above the SRMC of pivotal suppliers, is unlikely to reduce the efficiency of dispatch in the SWEM.

Resource adequacy

In practice, the impact of a pivotal supplier test on market prices depends on the frequency with which the test would apply. As discussed in the previous section, it is unlikely that the pivotal supplier test would trigger very frequently. Our analysis of historical data presented in Appendix E: Pivotal supplier test demonstrates the application of a pivotal supplier test is likely to have a marginal impact on average prices over the year.

Nevertheless, the introduction of a pivotal supplier test in the combined approach package may have a negative effect on resource adequacy if it reduces the frequency and duration of high priced events in response to tight market

59 By security constraints we refer to a set of linear constraints comparable to those included in the Market Clearing Engine that applied into the future and reflected likely changes to the transmission system consistent with any load flow modelling.

conditions in the SWEM. Capping the bids of pivotal suppliers is likely to reduce the resulting market prices earned by all market participants in trading intervals when the pivotal supplier test triggers. This may in turn reduce the potential for market participants to recover the fixed costs of their efficient investments. Accordingly, we have recommended an independent review of the level of the MPC to address any negative implications for resource adequacy with the introduction of the pivotal supplier test.

Intrusiveness and administrative burden

The application of a pivotal supplier test in the SWEM would be a relatively intrusive measure, as it involves the amendment of generators' bids and the re-running of the dispatch engine. The development of the detailed arrangements for the test, and implementation of the required changes to market rules, the dispatch engine and operating procedures, is likely to be costly and time-consuming for market participants, the EMA, the market operator and the system operator. After the test is operational, the ongoing administrative burden could be reduced if the test were devised appropriately – for example, by setting the bid cap at a sufficient level to avoid ongoing compensation claims.

Transparency and predictability

As with the balanced market approach, hedging MSSL load via the SGX facilitates transparency and predictability in the contract market. The addition of a pivotal supplier test with a raised MPC is likely to be relatively transparent and predictable, assuming the details of the test are publicly available and consistently applied.

6.7 Summary and conclusions

This Section introduced and assessed a number of packages that could be considered as alternatives to the current vesting contract arrangements to mitigate market power in the SWEM.

The **improved vesting contracts regime** involves incremental changes to the current vesting arrangements to address shortcomings of the status quo. In particular, the improved vesting contracts regime involves using a mechanistic approach to calculating the VCL, thereby improving the transparency and predictability of the vesting contracts regime. The reallocation of vesting contracts should enhance resource adequacy, while the introduction of a requirement to hedge unvested MSSL load means the improved vesting regime is likely to be slightly more effective at mitigating market power than the status quo arrangements. However, the improved vesting contract regime entrenches vesting contracts as a permanent feature of the SWEM.

The **balanced market regime** is the simplest of the alternatives considered. It involves phasing out vesting contracts and relying on competition in the wholesale market and the prudent hedging of unvested MSSL load to mitigate market power in the SWEM into the future. Our analysis demonstrates the balanced market regime is likely to be as effective as the status quo in managing market power and ensuring dispatch efficiency, while improving transparency and minimising administrative burden for all parties concerned. While the balanced market regime is not effective at mitigating the localised market power that arises due to transmission constraints, our analysis of historical and projected future events indicates this is not a major issue at the present time. If localised market power should become a significant issue in the SWEM the future, as a result of significant transmission congestion, a PST could be considered as a potential remedy.

The **combined approach** builds on the balanced market regime, adding a pivotal supplier test to address instances of localised market power. The pivotal supplier test would cap the bids of generators required to meet demand at a particular node or group of nodes, and should be paired with an independent review of the MPC to ensure overall resource adequacy for the market. The introduction of a pivotal supplier test means the combined approach is likely to be more effective at managing market power than the status quo. However, the imposition of such a test in the dispatch engine would be relatively intrusive, and may have adverse outcomes for the energy market depending on how it is operationalised.

7 Recommendations and conclusions

This Section summarises our recommendations and the conclusions of our analysis. It begins by discussing the comments made by stakeholders relevant to this section of the draft report (Section 7.1). Next it compares the assessment of the current arrangements for mitigating market power with the new packages of options presented in Section 6, recommending a preferred option (Section 7.2). It then considers the issues associated with transitioning to any of the alternative set of arrangements (Section 7.3). It concludes by summarising the market design principles and recommendations presented in this report (Section 7.4).

7.1 Comments on the draft report

Participant views on the recommendation to adopt the balanced market regime vary widely. Senoko Energy, Tuas Power and YTL PowerSeraya disagree with the proposal to move to the balanced market regime. They argue that the adoption of the regime fails to take into account the impact on the sustainability of generators. In contrast, many other market participants support the recommendation of adopting a balanced market approach. Buri Energy, Keppel, PacificLight Power and RCMA state their support for the balanced market regime. RCMA agrees that "the removal of the current burden and lack of transparency would be a positive aspect for the market and result in cheaper electricity costs for consumers".[60] Keppel qualifies its support for the balanced market regime, by suggesting BVQ should be reallocated based on effective capacity and a mechanism should be investigated to manage price separation events. PacificLight comment a gradual reduction in LNG vesting volumes may need to be considered prior to the expiry of these contracts in 2023.

We note the range of participant views, including the support of a number of stakeholders. On balance we continue to recommend the balanced market package on the basis that our analysis and modelling, and therefore conclusions, remain unchanged.

No comments were received regarding this section in the revised report.

60 Submission from RCMA, p1.

7.2 Comparison of alternatives

Section 6 presented a range of alternative packages for mitigating market power in the SWEM, which could be applied as alternatives to the status quo. Table 7 compares the assessment of the alternative packages against the status quo.

Introducing incremental changes to the existing arrangements under the **improved vesting contracts regime** improves the efficacy of the arrangements compared to the status quo. Although vesting contracts remain in place as the primary mechanism to mitigate market power, a revised contract allocation and the introduction of a requirement to hedge unvested MSSL load via the SGX (once certain pre-conditions have been met) ought to improve the effectiveness of the arrangements in managing market power and improve dispatch efficiency. The reallocation of the vesting contracts improves incentives for resource adequacy relative to the status quo, while the mechanistic approach to determining the VCL improves transparency and predictability. However, the improved vesting contracts regime effectively institutionalises vesting contracts as a permanent feature of the SWEM.

The light-handed approach to managing market power under the **balanced market regime** results in the most positive assessment compared to the status quo and other alternatives. The phasing out and ultimate removal of vesting contracts under the balanced market approach avoids the intrusiveness, administrative burden, and lack of transparency and predictability associated with the status quo. In the longer term once LNG vesting rolls off, market power in the SWEM under a balanced market regime would be managed via competition, including ensuring the prudent hedging of MSSL load, along with the market share cap and the existing provisions of the *Electricity Act*. Prudently hedging the unvested MSSL load acts as an effective mechanism to mitigate market power and enhance dispatch efficiency. While the balanced market approach is less effective than the alternatives in managing localised market power, it is not clear that localised market power is, or is likely to become, a significant issue in the SWEM. Should market conditions change such that future congestion exacerbates localised market power, the introduction of a PST may be a potential remedy.

The introduction of a pivotal supplier test and raised MPC under the **combined approach** improves the management of localised market power compared to the balanced market approach. As in the balanced market package, the phasing out and ultimate removal of vesting contracts under the combined approach improves resource adequacy and transparency and predictability compared to the status quo. However, the introduction of a pivotal supplier test represents a relatively intrusive modification to the market design, and is likely to involve significant development costs with potentially adverse consequences for market prices and resource adequacy.

Table 7: Comparison of alternative packages for mitigating market power in the SWEM

Package	Effectiveness	Dispatch efficiency	Resource adequacy	Intrusiveness/ administrative burden	Transparency and predictability
Status quo					
Improved vesting contracts regime					
Balanced market regime					
Combined approach					

On balance, we recommend the package of measures under the balanced market approach as the most effective, least intrusive and most transparent and predictable way to mitigate market power in the SWEM.

Recommendation 2 – Balanced market regime

We recommend the introduction of the balanced market regime to manage market power in the SWEM, comprising:

- Retaining the EMA's existing market monitoring and *Electricity Act* responsibilities.
- Replacing the capacity caps in the generation licences of the three largest Gencos by a 25% market share cap in all generation licences in a manner that does not force divestments under the current generation licences.
- Phasing out vesting contracts in several stages. First, gradually reducing balance vesting quantities to LNG vesting. Second, removing all vesting contracts once LNG vesting contracts have expired.
- Prudently hedging the unvested MSSL load.

7.3 Transitioning to the new arrangements

Transitioning to the balanced market package involves a number of changes to the status quo arrangements. As these changes are introduced, market participants will have existing market contracts and retail load exposures that need to be recognised and allowed for. Hence, it is important that the transition from the status quo proceeds in a staged and orderly manner to allow appropriate enabling arrangements to be developed, and to ensure market participants are able to adjust their portfolios as required.

In the longer term, the balanced market arrangements will need to be considered within the context of the end of the LNG vesting contracts. We suggest a systematic approach be adopted to ensure MSSL load remains hedged while minimising the potential market disruption associated with the expiry of LNG vesting contracts. This could involve entering into contracts to hedge MSSL load in the lead up to the expiry of LNG vesting.

Recommendation 3 – Transition path

We recommend a gradual adjustment from the status quo to the new arrangements over 2 to 3 years, taking into account the changes that may be required to support the new arrangements and the objective of ensuring an orderly transition.

The hedging of unvested MSSL load could involve a combination of SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

7.4 Summary of design parameters and recommendations

This report has provided a series of principles guiding the design of market power mitigation arrangements, and made a number of more specific recommendations relating to the optimal arrangements for managing market power in the SWEM.

These principles and recommendations are summarised in Table 8 and Table 9, respectively.

Table 8: Summary of design parameters

Number	Relevant packages	Design parameter
Design parameter 1: Minor enhancements to the existing vesting contract regime	Status Quo Improved Vesting	We recommend that the EMA amend the Procedures to reflect: • A maximum VCL limit and • The inclusion of directions or limits on the rate of change of the VCL.
Design parameter 2: Generation concentration cap	Improved Vesting Balanced Market Combined Approach	We recommend a capacity market share cap of 25% on all Gencos, that is implemented to ensure no forced divestment of physical capacity or currently held options to repower under the current generation licences.
Design parameter 3: Prescribed, vested HHI approach for setting VCL	Improved Vesting	We recommend setting the VCL based on a prescribed, formulaic methodology whereby the VCL would be set with a view to achieving an appropriately low 'vested HHI'. We propose that the VCL be set to achieve a vested HHI of 1,250, and reviewed periodically.
Design parameter 4: Vesting contract allocation	Improved Vesting	Vesting contracts should be allocated on the basis of the Gencos' effective capacity – where effective capacity refers to capacity that can respond to short term price events and currently equates to CCGT and OCGT plant capacities only. Allocations should be made to any effective capacity belonging to existing generators and any future new entrants.
Design parameter 5: Hedging	Improved Vesting	Unvested MSSL load should be prudently hedged. Such hedging could be via a combination of available SGX products, tenders and bilateral trades once appropriate trading, risk management

Number	Relevant packages	Design parameter
unvested MSSL load	Balanced Market Combined Approach	and compliance arrangements are in place.
Design parameter 6: Phase out vesting contracts	Balanced Market Combined Approach	Vesting contracts should be phased out under the balanced market approach in two key stages. First, balance vesting quantities should be reduced to zero over a defined period, say two to three years. Second, LNG vesting will be set to zero once the vesting contracts expire. Vesting contract allocation should remain unchanged over this period.
Design parameter 7: Pivotal supplier test	Combined Approach	A dynamic PST should be applied in the combined approach to identify suppliers that are required to meet demand in any import-constrained subnetwork (i.e. are pivotal) arising from transmission constraints. The bids of pivotal suppliers should be capped at a representative level, for example $350/MWh, representing an OCGT plant's SRMC with doubled fuel costs, to ensure participants are able to recover their variable costs. The PST should be designed to minimise any gaming and to remove incentives to physically withdraw capacity, which can primarily be achieved via implementing the test on a trading interval basis.
Design parameter 8: Market price cap	Combined Approach	Review the appropriate level of the MPC to enhance resource adequacy with reference to the market power mitigation measures adopted or to be adopted in the SWEM.
Design parameter 9: Analysis of pivotal supplier test (combined approach)	Combined Approach	To the extent that future circumstances in the SWEM exacerbate transmission congestion, further analysis regarding the appropriateness of a PST to manage localised market power should be undertaken. This would include load flow modelling to establish the extent to which transmission congestion is likely to occur in the SWEM and, ideally, further wholesale modelling with a more complete representation of the transmission system to quantify the impact of a PST.

Table 9: Summary of recommendations

Title	Recommendation
Recommendation 1: VCL for 2017 and 2018	We recommend that, conditional on prudently hedging the unvested MSSL load, there is scope to reduce the VCL to the LNG vesting level by the end of 2018. If the unvested MSSL load is not hedged, we recommend that the VCL be reduced to no lower than 20% for calendar years 2017 and 2018.
Recommendation 2: Balanced market regime	We recommend the introduction of the balanced market regime to manage market power in the SWEM, comprising: • Retaining the EMA's existing market monitoring and *Electricity Act* responsibilities. • Replacing the capacity caps in the generation licences of the three largest Gencos by a 25% market share cap in all generation licences in a manner that does not force divestments under the current generation licences. • Phasing out vesting contracts in several stages. First, gradually reducing balance vesting quantities to LNG vesting. Secondly, removing all vesting contracts once LNG vesting contracts have expired. • Prudently hedging the unvested MSSL load.
Recommendation 3: Transition path	We recommend a gradual adjustment from the status quo to the new arrangements over 2 to 3 years,, taking into account the changes that may be required to support the new arrangements and the objective of ensuring an orderly transition. The hedging of unvested MSSL load could involve a combination of SGX products, tenders and bilateral trades once appropriate trading, risk management and compliance arrangements are in place.

Appendix A – Review of international experience in market power mitigation

This Appendix reviews the experience of market power mitigation in a number of jurisdictions internationally. It begins by categorising market power mitigation mechanisms, before considering in turn the tools employed in the energy only markets of the Australian National Electricity Market (NEM), New Zealand Electricity Market (NZEM), the Texas ERCOT; and the energy and capacity markets of the PJM Interconnection (PJM) and the Irish Single Electricity Market (SEM).

At the outset it is important to recognise that the design of a market necessarily influences the type of market power mitigation mechanisms observed in that market. For example, in markets where a separate capacity mechanism provides the ability for participants and future investors to recoup some of their fixed costs mandated short-run marginal cost (SRMC) bidding rules are more likely. Conversely, energy-only markets tend to exhibit higher (or no) price caps and less restrictive bidding requirements, to enable participants and future investors to recoup the cost of their investments.

Introduction

Before reviewing the approaches to market power mitigation employed in electricity markets internationally, it is useful to broadly characterise the mitigation measures adopted. This section introduces a series of categories for market power mitigation mechanisms, which provide the framework for the discussion of each jurisdiction in this section.

System-wide price caps

Due to the highly inelastic nature of electricity demand in the short term, most electricity markets incorporate price caps to enable the market to clear if supply is insufficient to meet demand. In most energy-only markets, the level of the market price cap is set so as to incentivise sufficient generation capacity to meet reliability standards, without exceeding the price consumers are willing to pay for that outcome. In markets with a capacity mechanism, the market price cap is often set at levels closer to the SRMC of the highest cost plant.

Conditional price caps

Conditional price caps apply where, under certain circumstances, a new system-wide market price cap is imposed for a period of time. These types of caps typically take two forms:

- Scarcity pricing schemes whereby the market price cap is increased at times of supply scarcity.
- Cumulative price thresholds that impose a lower market price cap if a pre-defined threshold of prices is exceeded over a period of time.

Bidding behaviour restraints and obligations

Many markets have mandated bidding behaviour obligations as part of their market rules. Most markets do not impose explicit bid control mechanisms; rather, participants are permitted to freely submit bids based on their circumstances, but these bids may be subject to review under the rules if deemed anti-competitive.

Pivotal supplier tests are also a common mechanism in some markets. These tests are used to assess whether a generator has 'local market power' over a transmission constraint or within a region. When this occurs, the pivotal supplier typically has its offers capped at a level more reflective of their marginal costs.

Australian NEM

The Australian NEM incorporates a wholesale electricity market spanning south-eastern Australia. The NEM is an energy only, gross-pool, regionally priced market, with a market price cap (MPC) of AU$13,800/MWh, at which the spot price is set if supply cannot meet demand. The primary purpose of the MPC is to allow the spot market to clear at a price that incentivises sufficient generation capacity and demand-side response to meet the NEM reliability standard, while limiting the exposure of market participants and consumers to very high wholesale prices. The MPC is therefore set at a level to ensure that generators are able to recover both their variable and fixed costs over those short periods when supply is insufficient to meet demand.

The market power mitigation mechanisms in NEM include:

- A cumulative price threshold.
- Prohibition against misleading offers provisions (previously the bidding in good faith provisions).
- Market monitoring.

Each of these mechanisms is discussed in turn below.

Conditional price caps

Cumulative price threshold

While the NEM's MPC curbs incidences of very high prices in the spot market on a dispatch interval basis, an additional mechanism limits the exposure of market participants to prolonged periods of high wholesale prices.

Administered pricing is imposed when the sum of spot prices in a single region for the previous seven days (336 trading intervals) reaches a cumulative price threshold (CPT). The CPT is set at fifteen times the MPC, or $207,000 (equivalent to an average spot price of $616.07/MWh over the previous seven days) for the financial year ending June 2016, escalated annually by a price index like the MPC. Administered pricing is also triggered if the sum of prices for a market ancillary service for seven days exceeds six times the CPT.

While administered pricing is in force, market prices and dispatch are determined as normal. However, the Administered Price Cap (APC) of $300/MWh and Administered Price Floor (APF) of -$300/MWh are applied as upper and lower limits to published prices. Administered pricing continues until the end of the current trading day (0400 hours) unless spot market prices have continued to exceed the threshold.

Participants are allowed to claim compensation where they incur a loss during administered price periods under the National Electricity Rules. However, draft changes to the compensation arrangements are in process, limiting the objective of compensation to promoting reliability rather than also encouraging investment. Accordingly, under the proposed rules changes compensation will be restricted to the cost of supplying energy and consuming load, but excluding the recovery of capital costs currently allowed.[61]

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61 AEMC (2015) Draft Rule Determination – National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered price floor) Rule 2015

Bidding behaviour restraints and obligations

Bidding in good faith provisions

There are no explicit quantitative bidding behaviour restraints or obligations placed on NEM participants. However, in an attempt to combat harmful rebidding strategies in the period leading up to dispatch, the current National Electricity Rules require market participants to bid in good faith by submitting bids and rebids participants have a "genuine intention to honour".[62]

These provisions were originally introduced in 2002 due to concerns that wholesale price outcomes were being manipulated. However, a Federal Court decision in 2011 which rejected allegations by the Australian Energy Regulator that a generator, Stanwell Corporation, had made a number of bids that were not in good faith sparked arguments that the provisions were uncertain and ineffective. As a result Rule changes to take effect from 1 July 2016 will:

- Replace the current requirement that offers be made in good faith with a prohibition against making false or misleading offers.
- Require any variations to offers will need to be made as soon as practicable.
- Include a requirement to make and retain a contemporaneous record of the circumstances surrounding late rebids.

Suitability for Singapore

The NEM has relatively limited market mitigation measures in place. Despite this, wholesale prices are generally below the long-run marginal cost of supply in most regions and the AEMC considers most if not all of the market operates in a 'workably competitive' manner.

However, we do not advocate that the behavioural constraints on bidding that are in place in the NEM ought to be adopted in the SWEM. The NEM provisions do not prevent generators from engaging in physical or financial withholding of generation at times of high demand or constrained supply in practice, and have proved intrusive and administratively burdensome.

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62 National Electricity Rules, 3.8.22A Variation of offer, bid or rebid.

New Zealand Electricity Market

The NZEM operates across the North and South Islands of New Zealand. The NZEM is an energy-only, gross-pool market with full nodal pricing. Under system normal conditions, the NZEM has no system-wide price cap. However, there is an implicit price cap of NZ$3,000/MWh following a High Court decision in March 2013, which is intended to reflect the price that purchasers would have paid had they been aware of and therefore able to respond to a high price event.[63] Since this time, generation offers have tended to be around NZ$3,000/MWh during times when a generator finds itself to be net pivotal, or required to meet demand.[64]

The market power mitigation mechanisms in NZEM are:

- Scarcity pricing whereby market price limits are set between NZ$10,000/MWh and NZ$20,000/MWh during times of emergency load shedding.
- Safe harbour provision for bidding behaviour in pivotal supplier situations.
- Market monitoring.

Each of these provisions is discussed in more detail below.

Conditional price caps

Scarcity pricing

Scarcity pricing was introduced to the NZEM in October 2011, providing for a price floor and price cap in the event of widespread emergency load shedding. In the event of emergency load shedding generation weighted average prices will be calculated using the same methods as in system normal conditions. However, prices below the floor of NZ$10,000/MWh or above the cap of NZ$20,000/MWh are adjusted to reflect these limits. Scarcity pricing is revoked once the emergency load shedding ceases.

The market price floor and cap have been set to provide appropriate signals to investors. The market price floor is set to approximately reflect the cost of a last-

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63 EA (2012) Locally net pivotal generation Market Performance Review, p.33.

64 NERA (2013) *Review of alternative approaches to setting a wholesale electricity market price cap*, p.14.

resort peaking plant, and the market price cap is set roughly at the value of forgone consumption during a load shedding event. Together, the market price floor and cap provide a degree of revenue certainty for generators during these exceptional circumstances, as well as certainty to energy pool purchasers that pool prices will not be able to rise to unbounded levels.

A 'stop-loss' mechanism is also imposed whereby scarcity pricing is halted in the event that the average price over any seven day rolling period is greater than NZ$1000/MWh. This helps to protect wholesale energy purchasers from sustained high pool prices.[65]

Bidding behaviour restraints and obligations

Safe harbour provision and pivotal supplier situations

Rule changes relating to safe harbour provisions and pivotal supplier situations were introduced into the NZEM in July 2015. Generators are obliged to ensure that their offers are "consistent with a high standard of trading conduct".[66] A participant is deemed to comply with this requirement if its behaviour satisfies the following 'safe harbour' provisions:

- All its available capacity is offered.
- An offer is revised as soon as practicable.
- When it is a pivotal supplier, either:
    - its offers do not result in a material increase in the price in the region where it is pivotal;
    - its offers when it is pivotal are generally consistent with its offers when it was not pivotal; or
    - it does not benefit financially from an increase in the price in the region where it is pivotal.[67]

A pivotal supplier is defined as one who must offer at least some of its capacity so the system operation can meet demand in the affected region. A supplier may be pivotal in an entire island or both islands, or in a smaller region (locally

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65 EA (2011) *Scarcity Pricing – Overview.*

66 National Electricity Rules, Clause 13.5A.

67 National Electricity Rules, Clause 13.5A.

pivotal). Local pivotal supplier situations generally occur when there are temporary restrictions on transmission capacity.

Other mitigation measures

Undesirable Trading Situations

The NZEM market rules, or Code, set out the regime for dealing with an Undesirable Trading Situation. An Undesirable Trading Situation is any situation that threatens confidence in or the integrity of the wholesale market; or, in the opinion of the Electricity Authority, cannot be satisfactorily resolved by any other mechanism available under the Code; including, for example, manipulative trading activity or misleading or deceptive conduct.[68]

The Electricity Authority is able to investigate and take action against a participant who is suspected of engaging in the opportunistic exercise of market power, including for example directing trades be settled at a specified price.

Suitability for Singapore

The New Zealand concept of scarcity pricing could provide a useful model for Singapore. Scarcity pricing enables the wholesale market to clear when load is shed at prices that encourage investment in generation, while also providing an incentive for demand-side response.

However, we consider the safe harbour provisions relating to pivotal suppliers are too subjective to be appropriate for the SWEM. For example, it is unclear how a pivotal generator should predict whether its offer would be likely to result in a 'material increase' in the price in the region where it is pivotal. It is also unclear how such a generator ought to determine whether its offers when pivotal are 'generally consistent with' its offers when it was not pivotal. Failure to satisfy these safe harbour provisions leaves a pivotal generator open to the risk of being found to have behaved unlawfully.

68 National Electricity Rules, Clause 13.5B.

Electric Reliability Council of Texas regions

The Electric Reliability Council of Texas (ERCOT) is an energy-only, net-pool market with full nodal pricing. Under system normal conditions, a 'high' system-wide offer cap of US$9,000/MWh applies for all energy and ancillary services. The cap has been systematically increased each year from the cap of US$4,500/MWh in June 2013 to incentivise sufficient generation investment to secure future electricity supply, spurred by concerns about potentially inadequate generation investment resulting in tight reserve plant margins.

The current features of market power mitigation mechanisms in ERCOT are:

- A scarcity pricing mechanism whereby a relatively lower system wide cap can be imposed.
- Two-step market power mitigation, whereby participant offers are capped if it is determined a generator has local market power over a constraint.
- Voluntary mitigation plans.
- Exemptions for small players.
- Market monitoring.

These parameters are discussed in more detail below.

Conditional price caps

Scarcity pricing

The scarcity pricing mechanism is intended to provide pricing signals to incentivise new investment, while ensuring that market participants are protected against very high prices during periods of low reserve margins.[69] The scarcity pricing mechanism works by imposing a 'low' system-wide offer cap on participants in the event that reserve margins are low. The low system-wide offer cap is set on a daily basis at the higher of:

- US$2000/MWh for energy and ancillary services; and
- fifty times the daily natural gas price index of the previous Operating Day.

It applies so long as the Peaker Net Margin threshold, a proxy for the level of utilisation of peaking plant required to meet demand and intended to reflect the

[69] PUCT (2006) Order adopting amendment to S25.502, New S25.504 and New S25.505 as approved at the August 10 2006 open meeting, pp.40, 73.

levels estimated to support new entry of peaking plant, is less than or equal to US$315,000/MW.[70,71] If the threshold is reached, ERCOT imposes the low system-wide cap to protect market participants from further high price exposure during future periods of tight supply-demand conditions for the rest of the annual resource adequacy cycle.

The Operating Reserve Demand Curve (ORDC)

On 1 June 2014, ERCOT implemented an Operating Reserve Demand Curve (ORDC) applicable in the real-time energy market, to reflect the increasing value of reliability as reserves in the market becomes scarcer. The ORDC reflects the loss of load probability at varying levels of operating reserves multiplied by the VoLL (currently set at US$9,000/MWh). When the market approaches fixed operating reserve levels, the ORDC begins to pay money in accordance with the level of scarcity. It is currently not co-optimised with energy in the real-time market, with an ancillary service imbalance settlement applied in an attempt to ensure resources are indifferent between providing energy and reserves.

Bidding behaviour restraints and obligations

Two-step mitigation process

ERCOT's two-step market power mitigation mechanism works to limit the ability of generators to exercise market power in the event of binding transmission constraints. A Constraint Competitiveness Test (CCT) is applied to classify constraints into "competitive" and "non-competitive". The two-step process involves:

- First, simulating offer-based economic dispatch considering the competitive constraints and ignoring non-competitive constraints, yielding a set of 'reference' locational marginal prices.
- Second, mitigating or capping relevant energy offers around the non-competitive constraint at the greater of the reference local marginal price and

70 ERCOT calculates the accumulated Peaker Net Margin over each calendar year as the operating margins of a gas CT with a heat rate of 10MMBtu/MWh. This estimate excludes variable operating and maintenance costs, start-up and shut-down costs, emissions costs and imperfect dispatch.

71 ERCOT (2013) *System-wide offer cap and scarcity pricing mechanism methodology*.

a measure of plant variable cost. A series of conditions must be met for mitigation to be applied.

- Finally, a second round of offer-based dispatch simulation is used to calculate the final local marginal prices.[72]

When there is no overall scarcity of supply, the first step reference prices will be low and low offer caps will be set. Conversely, when there is scarcity, the first step will set higher offer caps, allowing capped prices to be higher when supply conditions are tighter. This allows for the mitigation of localised market power, while still limiting, to a degree, the impact of overall scarcity conditions in the market.[73]

Market conduct

The Public Utility Commission of Texas (PUCT) is charged with oversight and regulating public utilities in the State, and has responsibility for monitoring market conduct. The Texas Administrative Code requires the PUCT to consider whether any activity is inconsistent with ERCOT procedures; constitutes market power abuses or are unfair, misleading or deceptive; is consistent with the proper accounting for production and delivery of electricity; and adversely affected customers and market competitiveness, or interfered with system reliability or the efficient operation of the market. Market participants are expected to maintain guiding ethical standards, and are prohibited from engaging in activities which create artificial congestion, the unlawful restraint of competition, or the abuse of market power.

Voluntary mitigation plans

A Voluntary mitigation plan is an agreement between a generator and ERCOT that details exactly the conditions and market environment under which the generator will supply power to the real-time energy market, but not the day-ahead market, and at what prices this energy will be supplied. Some flexibility on offers under particular conditions for a portion of the participant's capacity can be negotiated in the agreements. Once accepted the plan creates a safe harbour for the generator against allegations of market abuse by withholding capacity.[74]

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72 ERCOT (2016) *ERCOT Nodal Protocols, Section 6: Adjustment Period and Real-Time Operations,* Section 6.5.7.3

73 Baldick (2010) *Restructured Electricity Markets: Market power.*

74 Before the PUC, Control Number: 40488, Application for Approval of Settlement Agreement.

'Small fish swim free'

Under the Texas Administrative Code generators with less than 5% of the installed generation capacity are deemed not to have market power. These participants are therefore exempt from being monitored, investigated or questioned about behaviour that may have otherwise been classified as the exercise of market power. Currently, the small fish threshold corresponds to approximately 4,000 MW. Over a period of four years, there were 491 hours with less than 4000 MW surplus capacity, implying 'small fish' would have been considered pivotal and in a position to increase the market clearing prices. The small fish exemption mechanism itself, but especially the limit at 5%, remains a controversial issue.[75]

Suitability for Singapore

Some of the market power mitigation measures applying in ERCOT warrant closer examination, as they apply in a market that is, like the SWEM, an energy-only market.

The two-step mitigation process effectively manages localised market power. It operates automatically through ERCOT's dispatch software, and therefore does not require the exercise of significant discretion by the regulator. This is an advantage over the mitigation arrangements operating in New Zealand and the Australian NEM.

However, the two-step mitigation process is that it is fairly intrusive, automatically mitigating the offer prices of generators whose output helps relieve transmission constraints. The risk with such mitigation is two-fold:

- It places a high degree of importance on the accuracy of each unit's 'mitigated offer cap', which serves as an estimate of the marginal cost of power from that resource. If the mitigated offer cap is too low, the generator will have poor incentives to make that unit available when it is most needed.
- It raises the risk that investors will face inadequate signals to facilitate the investment needed to satisfy the system's demand and reliability needs. As noted above, ERCOT has responded to this by raising the system-wide offer cap to US$9,000/MWh.

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75 See: http://www.platts.com/news-feature/2013/electricpower/ercot/index .

The 'small fish run free' exemption in ERCOT is problematic, and therefore unlikely to be beneficial in the SWEM.

PJM Interconnection

The PJM is an energy and capacity, net-pool market with full nodal pricing. PJM is comprised of a number of separate markets:

- Day-Ahead Energy Market.
- Real-Time (balancing) Market.
- Financial Transmission Rights (FTR) Market.
- Capacity market (the Reliability Pricing Model – RPM).

The market price cap was adjusted in December 2015, in response to concerns the historical arrangement was promoting cost based bidding inconsistent with production costs:

- The offer cap was doubled from US$1,000/MWh to US$2,000/MWh for cost-based offers.
- Market-based offers are capped at US$2,000/MWh, only when the corresponding cost-based offer is above US$1,000/MWh.
- Generators with demonstrated costs above US$2,000/MWh are able to recover those costs through make-whole payments.

The current features of market power mitigation mechanisms in PJM are:

- Reserve shortage price of US$3,700/MWh in times of scarcity.
- Three pivotal supplier test and cost-based bid capping where there is local market power over a constraint.
- No aggregate market power mechanisms.
- Anti-manipulation rule.
- Market monitoring.

Conditional price caps

Shortage pricing and the Operating Reserve Demand Curve

Since 2012, in the time leading up to and including periods of reserve shortage, PJM has implemented a shortage pricing mechanism. At these times PJM jointly optimises dispatch of energy and ancillary services. Recognising that there is an opportunity cost associated with reducing generation to maintain reserves, any marginal unit incurring such costs will have these costs reflected in the market local marginal price.

During shortage times, a total price cap on Local Marginal Prices of US$3,700/MWh applies, consisting of the regular US$2,000/MWh offer cap and up to a US$1,700/MWh cap (double the $850/MWh penalty) for reserves alone. This is to ensure that pricing is consistent with market conditions, but curbs the extent to which generators can exercise market power. In line with the recent revisions to the market price cap from US$1,000/MWh to US$2,000/MWh, the shortage pricing market cap was also increased from US$2,700/MWh to US$3,700/MWh.

Bidding behaviour restraints and obligations

Three pivotal supplier test and bid capping

In the PJM energy market participants submit both a cost-based offer and a market-based offer for each trading interval. If it is believed that the market-based offer may be non-competitive, the cost-based offer will be taken as the participant's final offer and effectively acts as a bid cap. The Three Pivotal Supplier (TPS) test, calculated automatically in the dispatch algorithm, is applied to assess the competitiveness of a submitted offer.

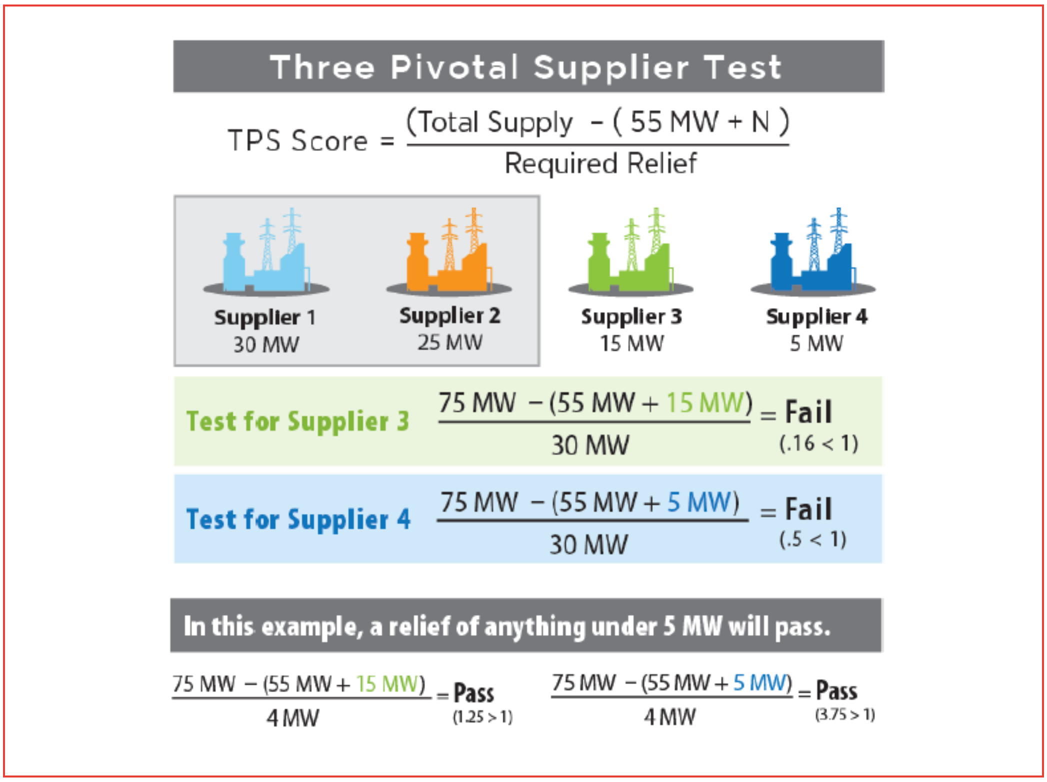
The TPS test was developed to screen for potential exercise of market power when generation resources are necessary to resolve a transmission constraint. It determines whether the supply of any single generation owner, when combined with the two largest remaining suppliers, is necessary to meet the required amount to relieve the transmission constraint. If the amount required to relieve the constraint cannot be met when removing the supply of the tested generation facility and the other two largest suppliers, then the tested facility is classified as 'pivotal' and all three parties will have their offers capped.[76] The two largest suppliers are not directly tested, since if one or more tested suppliers fail the test the two largest suppliers will also fail by definition. Indeed, the two largest suppliers can only pass the test if every other relevant supplier passes the test. For any local area assessed there must be at least four available suppliers for any supplier to be able to pass the test[77].

[76] PJM (2014) *Mitigation and Shortage Pricing in PJM Interconnection*.

[77] Monitoring Analytics (2015) Overview of the Three Pivotal Suppler Test

Figure 6 provides an example of the TPS test in application. Suppose 30 MW is required to relieve a transmission constraint. There is a total of 75 MW available from four different suppliers that could be used to relieve the constraint. Supplier 1 and Supplier 2 are the two largest suppliers and, together, they have 55 MW available. Under these conditions, both Supplier 3 and Supplier 4 will fail the TPS test because the sum of their capacities implies that remaining available supply (20 MW) is less than the required relief of 30 MW. Accordingly, Suppliers 3 and 4 along with Supplier 1 and Supplier 2, will have their offers capped. If, however, the required relief of the transmission constraint is 4 MW, then both Supplier 3 and Supplier 4 will pass the TPS test and no suppliers (including Suppliers 1 & 2) will have their offers capped.

Figure 6: Example of the three pivotal supplier test



Source: PJM Interconnection (2014) "Mitigation and Shortage Pricing in PJM Interconnection", p.5.

Anti-manipulation rule

The Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the PJM Interconnection (among other energy markets) under the *Federal Power Act 2005* (the Act). The Act includes 'anti-manipulation rule', intended to prohibit market manipulation in the energy market, which makes it unlawful to defraud, make untrue or misleading statements, or engage in acts of fraud or deceit. The FERC has the under the Act power to disgorge unjust profits and impose civil penalties for a breach of the anti-manipulation rule.

Suitability for Singapore

The relatively strict bidding restraints and low market price cap adopted to manage market power in PJM are closely related to market design. The existence of a capacity mechanism has meant that policy-makers could adopt a relatively firm stance against generators offering power at high prices, secure in the knowledge that those generators had another source of income to fund their plant investment. We would not recommend such tight constraints on bidding in an energy-only market, such as the present SWEM.

Ireland Single Electricity Market

The SEM is an energy and capacity, gross-pool market with a single pricing region, with a market price cap of €1,000/MWh. The market dispatch algorithm effectively caps generator bids, and therefore the resulting market prices, to mitigate the risk that the market does not clear due to insufficient generating capacity (resulting in load shedding), prevent the market price rising above the VoLL, and provide a safeguard against the exercise of market power.[78]

The current features of market power mitigation mechanisms in SEM are:

- A bidding code of practice which effectively mandates SRMC bidding.
- Directed contracts which are contracts for differences.
- Vertical ring-fencing of the large vertically integrated 'gentailer' ESB.
- Local market power mitigation over constraints.
- Market monitoring.

For the rest of this section, we discuss market characteristics and design in terms of the currently implemented SEM.

Conditional price caps

There are currently no conditional price caps in the SEM.

78 All Island Project (2007) *The value of lost load, the market price cap and the market price floor*, p.7.

Bidding behaviour restraints and obligations

Bidding Code of Practice

The Bidding Code of Practice (BCoP) sets out the principles generators are required to adhere to when offering submitting energy into the pool, effectively mandating generators to bid in their capacity at their SRMC. This is intended to yield efficient price outcomes reflecting the true marginal cost of meeting demand. Generators can freely submit bids based on its circumstances and operating environment, however these bids may be subject to review against the principles if deemed anti-competitive.[79]

Other mitigation measures

Directed contracts

Directed contracts are the cornerstone of market power mitigation in the SEM. Directed contracts are contracts for differences (CfDs) imposed by the regulatory authorities on the incumbent generators with a large market share; namely ESB. Similar to vesting contracts, directed contracts mitigate the incentive of the contract holders to exercise market power. The regulatory authorities determine the quantities, prices and allocation of these contracts.

The quantities of directed contracts generators are obliged to offer are determined using a 'Concentration Model'. This model calculates the quantities of contracts that generators need to offer to reach an HHI threshold of 1,150. HHIs are calculated by quarter for three different generation market segments (baseload, mid-merit and peaking), on a rolling five quarter-ahead basis. If the HHI exceeds the threshold level for each of these segments, the incumbent with the largest baseload market share in that month is allocated directed contracts of 1% of that share. This is repeated, with allocated quantities excluded from the HHI, until the monthly baseload HHI is below the 1,150 threshold level.

The prices of directed contracts are determined using regression formulae that express the contract strike price in a given quarter and for a given product (baseload, mid-merit or peak) as a function of forward fuel and carbon prices.

79 All Island Project (2006) *Market Power Mitigation in the SEM – Bidding Principles and Local Market Power*, p.8.

Vertical ring-fencing

Prior to the start of the SEM, vertical ring-fencing arrangements were imposed by the regulators on the two large incumbents: Electricity Supply Board (ESB) and Viridian/NIE[80] businesses. These arrangements would ensure that the generation arm of the firm operates as a separate business from the retail supply arm of the firm. Ring-fencing works by enforcing separate management and financial accounts, prohibiting cross-subsidies and mandating arm's-length contracting arrangements on normal commercial terms. Without these arrangements, generators may be incentivised to sell electricity to their supply arm at discount prices, resulting in anti-competitive market outcomes.[81]

Local market power mitigation

The SEM features a three-step sequential process to mitigate the potential for generators to manipulate their position on the transmission system:[82]

- First, the bidding behaviour of participants is be monitored for compliance with the bidding principles in the BCoP.
- If the administration of the BCoP becomes too burdensome, either because the number of enquiries is excessive or the issues arising in particular enquiries become intractable, the regulatory authorities will impose targeted capping of constraint payments to limit the scope for the payoffs of the exercise of market power. The caps on constraint payments are set with the intention of retaining a strong signal for more supply from generators in constrained locations while not 'excessively enriching' generators with local market power.
- Finally, if these caps are 'intolerable' to the generator with local market power, full Reliability Must Run (RMR) contracts are applied to these generators, providing out-of-market contract payments to the generator.

80 ESB acquired the Northern Ireland Electricity (NIE) assets in December 2010, p.5.

81 The Competition Authority (2010) *Competition in the Electricity Sector.*

82 All Island Project, (2006) *Market Power Mitigation in the SEM – Decision paper.*

Suitability for Singapore

The market power mitigation measures in the SEM are similar to those in the PJM, although a less mechanistic approach is adopted for bidding principles and bid capping. These less mechanistic approaches may be more appropriate in the context of Singapore's energy-only market, if they are applied in a predictable manner. The approach used to calculate the volume of directed contracts may provide the basis for a more transparent and predictable approach to determining the volume of vesting contracts in the SWEM.

Appendix B – *SPARK* market modelling

Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occurs in the market. Unlike most other models, however, generator bidding behaviour is a modelling output from *SPARK*, rather than an input assumption. That is, *SPARK* calculates a set of 'best' (i.e. sustainable) generator bids for every market condition. As market conditions change, so does the 'best' set of bids. *SPARK* finds the 'best' set using advanced game theoretic techniques. This approach, and how it is implemented in *SPARK*, is explained in more detail below.

Comments on the draft report

Senoko comment on our approach to modelling strategic interactions in electricity markets, questioning our choice of a single-shot game approach (as opposed to a repeated game approach). As discussed below, in developing *SPARK* we have extensively tested a range of theoretical and empirical approaches to assessing strategic issue in competitive electricity markets, including repeated games. Our conclusion is that single-shot Cournot game approaches provide the best approximation to actual competitive behaviour in wholesale electricity markets.

Comments on the revised report

Senoko made a number of further comments about the modelling analysis in response to the revised report, noting the modelling analysis has not been demonstrated to be based on reasonable assumptions. For example, Senoko comment that retail contract levels should be treated as dynamic as the VCL evolves and the base and bidding sensitivities underestimate the likely offer of peaking plant.

In response we note that retail market outcomes are important and may influence pool price outcomes depending on the i) extent to which retail load is hedged or exposed to the spot price, and ii) the allocation of retail load among participants. We believe the former effect to be dominant and have investigated this through the treatment of MSSL load in the modelling analysis. Accordingly, our recommendation is contingent on that load being hedged. While the second factor is important, actual market share in the future is uncertain and will be a function of vesting and other factors. For the purposes of our analysis we have therefore assumed historical market shares will remain the same in the future. As noted above the relationship of aggregate contract cover to aggregate demand remains the most important influence in this context.

We note Senoko's comments relating to bidding assumptions. However, we maintain that our modelling assumptions were developed to reflect a range of potential outcomes and therefore remain robust.

Data required for *SPARK*

SPARK requires a representation of the physical and economic characteristics of the market in order to determine the 'best' set of generator bids for every market condition. This includes a representation of demand and supply side inputs such as the capacity, SRMC, ownership and other parameters relevant to each generating unit in the market.

The model is used to optimise dispatch decisions in electricity markets. Specifically, the model seeks to minimise the variable cost of meeting electricity demand, subject to a number of constraints. These constraints include that:

- supply must exactly meet demand at all times
- minimum reserve requirements must be met
- generators cannot run more than their physical capacity factors
- additional constraints, including transmission limits, are met

In *SPARK* game theory is used to determine market outcomes where at least some market participants are allowed to behave strategically in the spot market. This strategic behaviour of market participants within *SPARK* occurs within the constraints of the physical and economic characteristics of the market and the market rules. Reflecting this, *SPARK* also requires input assumptions about which assets can behave strategically and what strategies are available. In most cases some level of firm contract cover is also assumed for the strategic assets to model the actual incentives of generators.

Model formulation

Game theory is a branch of mathematical analysis which is designed to examine decision making when the actions of one decision maker (player) affect the outcomes of other players, which may then elicit a competitive response that alters the outcome for the first player. Game theory provides a mathematical, and therefore systematic, process for selecting an optimum strategy given that a rival has their own strategy and preferred position. Organised electricity markets are well suited to the application of game theory:

- there are strict rules of engagement in the market place;
- there is a well-defined and consistent method for determining prices and, hence, profits; and
- the interaction between market participants is repeated at defined intervals throughout the day.

There are several basic concepts that underpin the game theoretic approach:

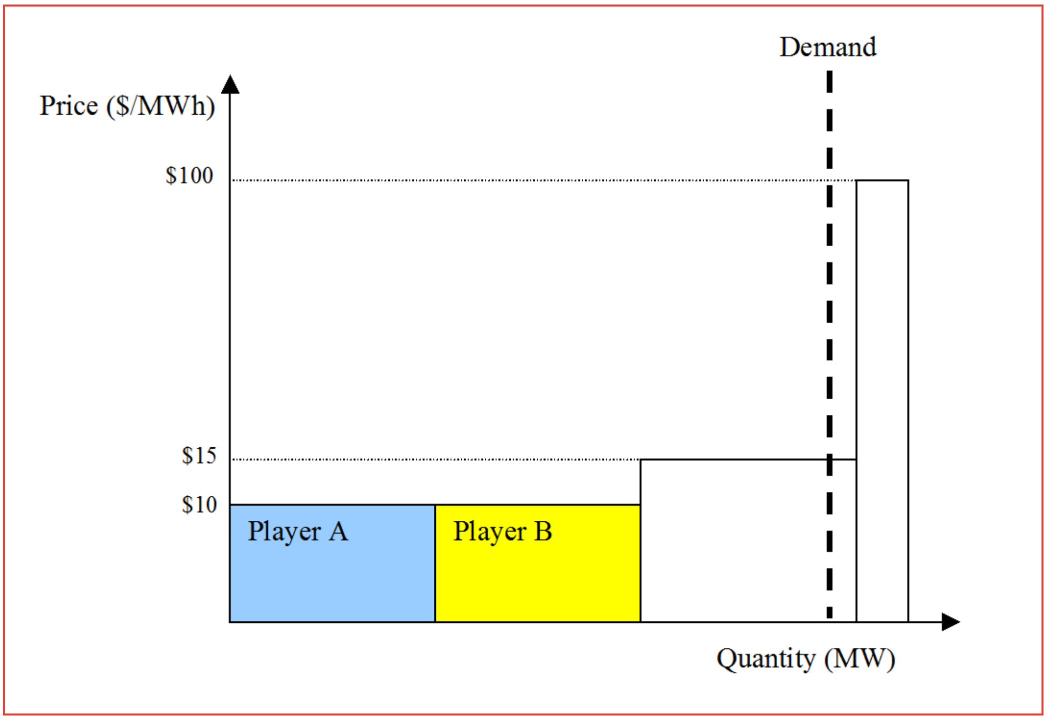
- **Players**: players are generators who are able to make decisions based on the behaviour they know or expect from other players. *Strategic players* are given a range of different strategies allowing them to respond to changes in the behaviour of other players. *Non-strategic players* have a fixed strategy and hence are unresponsive to the behaviour of other players.
- **Payoffs**: in every game, players seek to maximise pay-off (i.e. operating profit) for a given set of competitor strategies.
- **Nash Equilibrium:** an equilibrium describes a 'best' set of choices by the players in the game. An equilibrium is 'best' in the sense that each player is choosing its profit maximising strategy subject to the strategies being pursued by the other players. Thus, an optimal outcome is not necessarily one that maximises a particular player's profits.

Applying game theory to the electricity market

Consider a simple example of an electricity market. The market is a single regional market, with 2 Players, A and B. Players A and B are of equal size (say, 100MW) and have equal costs (say, $10/MWh). There are also other generators in the market, with higher costs (one at $15/MWh and another at $100/MWh). An aggregate supply and demand diagram for this simply market is shown in Figure 7.

In this example, demand is at a level above the combined capacities of Players A and B, intersecting with the first higher cost generator. The result is that the market price is determined by the bids of the first higher cost generator, at $15/MWh. Both Player A and Player B make a small profit equal to $5/MWh, multiplied by their output of 100MWh, giving $500 each.

Figure 7 Example supply/demand diagram



Under these conditions, either Player A or Player B could withdraw a small amount of capacity to push the price up to the cost of the second higher cost generator ($100/MWh). Assume Player A withdraws 10MW, and that this is sufficient to set the price at $100/MWh. This results in the following profit outcomes:

- Player A's profit becomes 90MW*($100-$10) = $8,100
- Player B's profit becomes 100MW*($100-$10) = $9,000

Conversely, Player B could withdraw 10MW, and the profit results would be reversed. If both Player A and Player B withdrew 10MW, the price would be set at $100/MWh, resulting in the following profit outcomes:

- Player A's profit becomes 90MW*($100-$10) = $8,100
- Player B's profit becomes 90MW*($100-$10) = $8,100

Using these results, we can construct a game payoff matrix as shown in Figure 8.

		Player B	
		Bid 100MW	Bid 90MW
Player A	Bid 100MW	\$500, \$500	\$9,000, \$8,100
	Bid 90MW	\$8,100, \$9,000	\$8,100, \$8,100

Figure 8: Payoff matrix (Player A, Player B)

Note: Payoffs are in Player A, Player B order.

Now consider Player A's incentives:

- If Player A thought Player B would bid 100MW, Player A would do best by bidding 90MW for a profit of \$8,100 (compared to \$500 by bidding 100MW)
- If Player A thought Player B would bid 90MW, Player A would do best by bidding 100MW for a profit of \$9000 (compared to \$8100 by bidding 90MW)

As the game is symmetric, Player B faces the same incentives. In this example, we have two equilibria, (A=90MW, B=100MW) and (A=100MW, B=90MW). At either equilibrium point, no player can increase its profits by unilaterally changing its bid – that is, both these points are Nash Equilibria.

Game Theory in SPARK

SPARK includes a representation of the physical and economic characteristics of the market (including technical and cost data for generation plant, interconnectors between regions and greenhouse and renewable energy policies.

There are a number of steps required in *SPARK* modelling.

First, generators need to be divided into two categories:

- *Strategic players* are given a set of strategies (i.e. choices of capacity or prices to bid into the market), and will respond to changes in the choices of others, in order to maximise their payoffs
- *Non-strategic players* are assigned fixed bids (i.e. their bids remain constant no matter how other players bid), which do not respond to changes in the choices of others

The definition of strategic players is based on observation of historic bidding behaviour. In effect, the generators that are defined as strategic players are those generators in the market that have the largest portfolios of generation plant.

As well as defining strategic players and non-strategic players, it is necessary to identify ownership of each generation plant (including new entrant plant) in the system.

Second, the type of bidding and the range of bidding choices must be defined. Regarding the type of bidding, *SPARK* can be operated with a choice of capacity bids or price bids. Capacity bids (Cournot modelling) are equivalent to withdrawing capacity. Price bids (Bertrand modelling) are equivalent to increasing prices. Regarding the range of bidding choices, under Cournot games, bidding choices are represented by increments of capacity withdrawals. Under Bertrand games, bidding choices are represented by multiples of SRMC. Given the computational demands of game theory it is important to limit the number of bidding choices as the number of dispatch operations rises exponentially as the number of strategic players and bidding choices increases[83].

Third, the contract levels of players must be defined. Contract levels affect the operating profits that players receive under each set of strategies. *SPARK* computes prices and operating profits for each combination of bids and for each demand point.

Operating profits for a portfolio of assets are calculated as pool revenue less variable costs of generation plus any difference payments on a contract position. Mathematically, this can be expressed for a single bidding combination and level of demand as:

$$\pi_{portfolio} = \left[\sum_{Generators,i} (P - MC_i).Q_i \right] + \left[\sum_{Swaps,j} (S_{Swap} - P).V_{Swap} \right] + \left[\sum_{Caps,k} Min(P - S_{Cap}, 0).V_{Cap} \right]$$

Where,

P = Market price

MC_i = Marginal cost of generator i

Q_i = Output of generator i

S_{Swap} = Assumed strike price of portfolio swaps

V_{Swap} = Assumed volume of portfolio swaps

S_{Cap} = Assumed strike price of portfolio caps

V_{Cap} = Assumed volume of portfolio caps

83 For example, including 10 strategic bidders with 4 possible bidding strategies results in a payoff matrix with 1,048,576 (4^10) elements (corresponding to each bidding combinations) from which to identify Nash equilibria for a single demand point!

Note that contracts are only included in order to capture their effect on marginal bidding decisions. Put another way, we are only interested in whether a particular bidding combination leads to a better or worse outcome for a Player relative to its other bidding options. As such the premium paid on caps is irrelevant as it is a constant across all bidding combinations and is not included in the calculation. The particular strike price of swaps is also irrelevant as it only changes the level of payoffs, it does not change the relative payoffs between bidding combinations. Any swap strike price will give the same set of optimal bidding outcomes. Floors and more exotic contracts can also be included in the model however Frontier does not propose to utilise these contract types as part of this analysis.

The operating profits are used to measure the 'payoff' for a game. Once payoffs for all possible combinations of bids have been computed, *SPARK* searches for the Nash Equilibrium. In effect, *SPARK* identifies equilibrium strategies on the basis of a grid search of the possible strategy space, as illustrated (for a two strategic player game) in Figure 9. PA_i and PB_j represent the bidding strategies of players A and B respectively. VA_{ij} and VB_{ij} represent the pay-offs (operating profits) for the strategy combination. *SPARK* searches the set of possible outcomes of the one-shot game for Nash Equilibria, without considering how the players arrive at a particular outcome.

Figure 9 Hypothetical example of *SPARK*'s strategy search

PA_n	VA_{n1} VB_{n1}	VA_{n2} VB_{n2}	VA_{n3} VB_{n3}	VA_{n4} VB_{n4}	.	.	.	VA_{nm} VB_{nm}
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
PA_4	VA_{41} VB_{41}	VA_{42} VB_{42}	VA_{43} VB_{43}	VA_{44} VB_{44}	.	.	.	VA_{4m} VB_{4m}
PA_3	VA_{31} VB_{31}	VA_{32} VB_{32}	VA_{33} VB_{33}	VA_{34} VB_{34}	.	.	.	VA_{3m} VB_{3m}
PA_2	VA_{21} VB_{21}	VA_{22} VB_{22}	VA_{23} VB_{23}	VA_{24} VB_{24}	.	.	.	VA_{2m} VB_{2m}
PA_1	VA_{11} VB_{11}	VA_{12} VB_{12}	VA_{13} VB_{13}	VA_{14} VB_{14}	.	.	.	VA_{1m} VB_{1m}
	PB_1	PB_2	PB_3	PB_4	.	.	.	PB_m

SPARK treats each demand point individually when running a game. That is, a game is considered to occur for a particular representative demand point. In analysing multiple demand points, a number of games, one for each demand point, are run.

Multiple Nash Equilibria

Frontier Economics has utilised our strategic bidding and dispatch model, *SPARK*, to compare potential SWEM wholesale outcomes given different VCLs and whether or not unvested MSSL load is otherwise hedged.

SPARK is a plant dispatch model that utilises game theory to identify sets of generator bidding strategies that yield Nash Equilibria. A Nash Equilibrium is a set of strategies where no party (in this case, no Genco) has an incentive to unilaterally deviate from its strategy. Put another way, a Nash Equilibrium is a situation where given the strategies adopted by other parties, no single party acting on its own can increase its payoff by changing its strategy. This does not imply that a Nash Equilibrium will represent an optimum set of strategies for the parties concerned, or that the parties' strategies will naturally tend towards Nash Equilibria outcomes. Rather, a Nash Equilibrium simply means that the set of strategies in question is *stable*, in that there are no endogenous forces that will encourage the relevant parties to shift away from their strategies.

Depending on the number of generators modelled as strategic players, *SPARK* will often identify multiple Nash Equilibria for any given set of demand, plant and network conditions. *SPARK* can identify multiple equilibria because it tests *all* potential combinations of offers by generators deemed to be strategic in order to ascertain whether any given combination of offers represents a Nash Equilibrium. This may involve testing tens of thousands of bidding combinations at a given level of demand. This exhaustive testing process is what sets *SPARK* apart from many other dispatch models, which commence with a particular set of bidding strategies and then iterate bids until a single Nash Equilibrium is found (if any).

The identification of multiple Nash Equilibrium by *SPARK* is a critical feature of the model, as even in the simplest games – such as the well-known 'Battle of the Sexes' and 'Chicken' games[84] – multiple Nash Equilibria arise. Quantifying all of these possible outcomes is necessary to analyse overall bidding behaviour. Where *SPARK* finds multiple equilibria, we report the average of the equilibria outcomes rather than any single Nash Equilibrium outcome to ensure our results are not distorted by extreme cases.

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84 See Fudenberg, D. and J.Tirole, *Game Theory*, (2000) Seventh printing, The MIT Press, p.18.

Repeated games

There has been some confusion in previous VCL reviews regarding the modelling of repeated interactions amongst the Gencos and whether the EMA needs to model multi-round or 'repeated' games as opposed to just 'single-shot' games. The rationale for modelling repeated games is that the SWEM involves repeated interactions between generators and some high-price outcomes may only appear as equilibria in repeated games. Therefore, modelling one-shot games (only) could understate the potential for the Gencos to exert market power to raise prices and profits.

We note that any Nash Equilibrium that can be sustained in a repeated game but not in a single-shot game relies on the ability of players to engage in some form of threat and punishment or 'retaliation' strategies. However, in a finitely-repeated game, any Nash Equilibria will be exactly the same as in the single-shot game.[85] As Shapiro says:[86]

> Quite generally, the unique subgame perfect equilibrium of a finitely repeated game with a unique Nash equilibrium in the stage game is a simple repetition of the stage-game equilibrium.

Infinitely-repeated games (or 'supergames') are different. If firms interact an infinite number of times, or they are not sure when their interactions will end, then collusive outcomes – those yielding higher profits for all players than the single-shot Nash Equilibrium[87] – are possible. This is because there is always scope for punishment strategies to be effective if the firms' interactions are ongoing. Friedman showed that tacit collusion can support any mutually-beneficial outcome in an oligopolistic infinitely-repeated game if the players are extremely patient and/or if participants can respond rapidly to each other.[88] Tacit collusion refers to behaviour where firms act as though they have colluded.

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85 Assuming that each stage of the game must be subgame-perfect, as is the standard approach.

86 Shapiro, C., "Theories of Oligopoly Behaviour", Chapter 6 in *Handbook of Industrial Organization*, Volume 1, Schmalensee, R and R. Willing (Eds), North Holland (1989), p.360.

87 This property is known as 'individually rational'. An outcome is individually rational for firm i if it gives that firm a payoff no lower than the one that firm i could guarantee itself against any play by the other n-1 firms. See also Fudenberg, D. and J.Tirole, "Noncooperative Game Theory", Chapter 5 in *Handbook of Industrial Organization*, Volume 1, Schmalensee, R and R. Willing (Eds), North Holland (1989), p.279.

88 Friedman, J.W., (1971) 'A noncooperative equilibrium for supergames', *Review of Economic Studies*, Volume 38, pp.1-12, p.11.

We believe that modelling repeated games introduces an element of subjectivity that undermines the usefulness of applying Game Theory to electricity markets. Outcomes are only likely to be different in the case of infinitely repeated games. Defining a set of multi-period retaliation strategies and discount rates for each participant is, we feel, indistinguishable from assuming an outcome involving perpetual tacit collusion contrary to the entire forecasting exercise. This view is informed by our empirical work and experience in modelling electricity markets for more than 15 years.

Further, we note that the EMA Procedures clearly state that the Authority will use modelling to simulate *non-collusive interactions* amongst the Gencos. To the extent that certain Nash Equilibria arise only in repeated games and not in one-shot games, such Nash Equilibria can be said, *ipso facto*, to reflect tacit collusion. Therefore, the identification of sets of Nash Equilibrium bidding strategies that only appear in repeated games falls outside the scope of outcomes that the EMA has stated it will model for the purposes of setting the VCL.

This is not to say that the collusive outcomes that can arise in repeated games are acceptable or do not raise concerns. However, the likelihood of such collusive equilibria arising in practice is even more difficult to predict than the likelihood of any single-shot Nash Equilibria arising. So-called 'folk theorems' show that under quite general conditions, repetition of any collusive outcome in the one-shot game can be supported as a supergame equilibrium with sufficiently little discounting.[89] The range of potential supergame equilibria depend on how the parties agree on sequences of actions and the punishment strategies that are used against those who deviate from that sequence. Opening up the VCL modelling process to test for repeated-game Nash Equilibria is liable to result in greater subjectivity and imprecision of outcomes.

89 Shapiro, C., "Theories of Oligopoly Behaviour", Chapter 6 in *Handbook of Industrial Organization*, Volume 1, Schmalensee, R and R. Willing (Eds), North Holland (1989), p.366.

Appendix C – Market modelling inputs

Both the task of setting the vesting contract level (VCL) for 2017 and 2018 and the task of reviewing potential new mechanisms to mitigate market power in the SWEM make use of Frontier's electricity market model *SPARK*. To this end, the two tasks share the vast majority of model input assumptions including:

- The assumed SWEM regional structure and generation facilities located within each region
- System and subregional demand
- System supply, including unit operating parameters and fuel costs
- Generation and flow constraints, including transmission/network constraints and gas take or pay (TOP) arrangements
- Contracting arrangements
- Bidding strategies

Whilst the task of reviewing potential new mechanisms to mitigate market power is essentially an exercise in *comparative statics*, that is, we focus on the difference between cases allowing for some simplifying assumptions, setting the VCL requires accurately forecasting *absolute* price outcomes in the NEMS and a more complete treatment of possible price effects due to changes in the vesting level. This requires an extension to the modelling performed in the review of potential new market power mitigation mechanisms. Specifically, for setting the VCL we have incorporated generator forced outages on a stochastic basis as opposed to the average derating method used for the market power mechanisms study.

In this section of the report we discuss each of these modelling inputs in greater detail.

Comments on the draft report

Participants, most notably Senoko, requested further information on the inputs to the modelling and our approach. Additional information has been included in this section.

No comments were received regarding this section in the revised report.

Modelling forecast period

Our modelling for setting the VCL covers the calendar year 2017 and 2018 period, which is the focus of the review. Due to the computationally intensive nature of including stochastic outages in the modelling task, reserving the forecasts to these two years allows for more investigation and sensitivities to be conducted.

For the alternative market power mechanism modelling task, which has a number of wider considerations relating to implementation timelines and mechanism structure, we have extended our forecasts out to 2020, so that the period of analysis covered is 2017-2020. In practice, no changes to market mechanisms would be able to be implemented before 2017, so we did not view it necessary to model 2016.

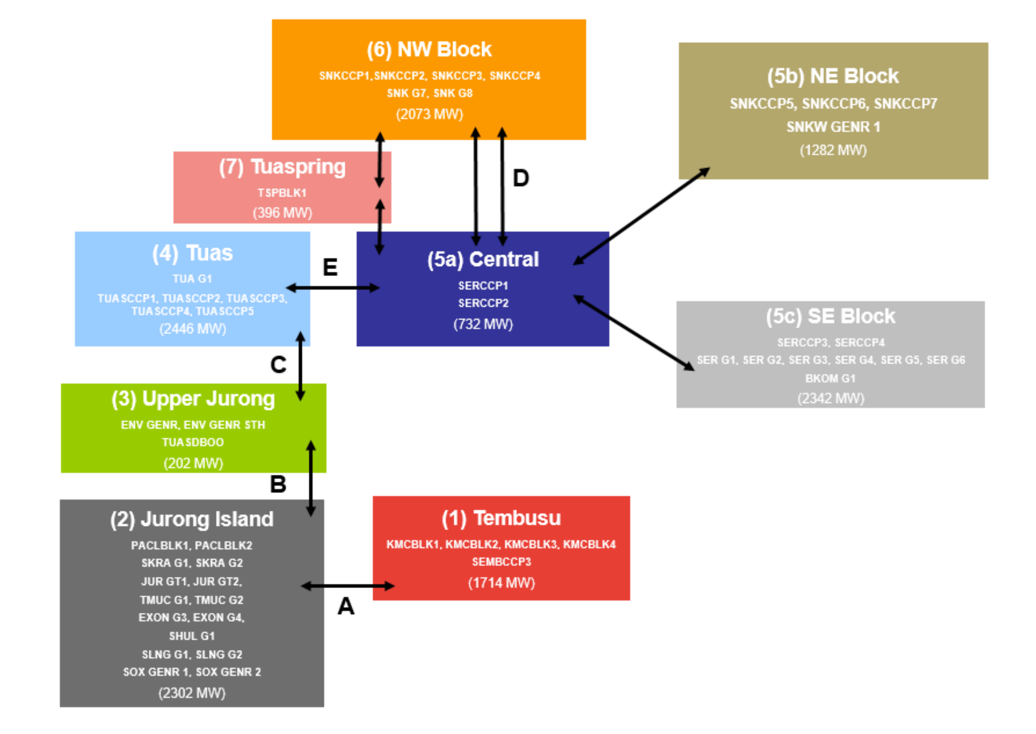
For both tasks we have undertaken modelling for 2015 to be used as part of the calibration process, as outlined in Appendix D – Market modelling calibration.

Network structure

Without the provision of full constraint and network configuration information it is not possible to model the SWEM as a fully nodally-priced market. Thus, absent this information, a simplified regional structure was assumed which could be used to serve the purpose of obtaining regional nodal prices to proxy for the nodally priced SWEM in the wholesale market modelling. Assuming a simplified regional structure pertained to defining a set of subregions with associated generation units, relevant transmission constraints and distribution of load across these regions.

The subregions and some relevant basic characteristics are illustrated in Figure 10 and described in further detail in the sections below.

Figure 10: Assumed regional structure of the SWEM



Source: Frontier Economics summary of EMA information

- *Blocks represent subregions and are numbered items. Non-GSF units are listed*
- *Arrows represent possible flows between regions, security limits labelled using letters*
- *Total registered capacity of non-GSF units recorded in brackets at bottom of block*

Regional Structure

The EMA provided Frontier with nine subregions and the corresponding units operating within those subregions. In general, these region have been defined in such a way that are separated by large transmission constraints or geographical/load separation. These regions are pictured in Figure 10 and are characterised as:

- Tembusu, which includes the entire Keppel portfolio and one Sembcorp unit
- Jurong Island, separated from Tembusu by constraint A, which contains the PacificLight portfolio, two Sembcorp units, Seraya's two OCGT units and some smaller generation facilities
- Upper Jurong, separated from Jurong Island by constraint B, which contains some smaller generation units
- Tuas, separated from Upper Jurong by constraint C, contains the entire Tuas portfolio
- Central, containing two large Seraya units
- SE Block, containing the remaining Seraya units including their steam units

- NE Block containing three large Senoko units
- NW Block, separated from Central by constraint D, containing the rest of Senoko's portfolio
- Tuaspring, located between NW Block and central and containing only the generation unit Tuaspring

Load distribution

The EMA provided Frontier with information regarding the distribution of load across the nine subregions defined, which served to determine the relevant subregional demand.

Transmission constraints

High level information regarding line limits and dates in effect (presently and into the future for the duration of the forward modelling period) for transmission constraints between the subregions were provided by the EMA to Frontier. Frontier incorporated this information into the modelling under the following principals:

- Flows are bidirectional, that is, flow can travel between regions in either direction.
- We have assumed for modelling purposes that flows between regions travel along notional interconnectors which either have line limits assigned to them if relevant security limits apply, or have no limit.
- Since modelling is conducted based on clustered subregional *annual* load duration curves (see Demand below), security limits must apply (or not apply) on an annual basis.
- Only those security limits which are relevant to the forward modelling period are included as flow constraints on the notional interconnectors in the model. Further, derating transmission line limits for planned maintenance works which were not expected to occur into the future were not included in the modelling.
- For the majority of flows between regions we have modelled notional interconnectors as independent DC links (consistent with the treatment in the Market Clearing Engine (MCE)). However, in the regional representation assumed, flows between Central and NW Block can run either direct or via Tuaspring; thus forming a loop. To correctly electrically account for this loop flow, Frontier has modelled the notional interconnectors in this loop as AC links with impedances. Impedances were provided by the Power System Operator (PSO) to Frontier. Upon implementing these impedances in SPARK it was found they did not adequately generate flows in accordance with historical outcomes. It was unsurprising that impedances relevant to the

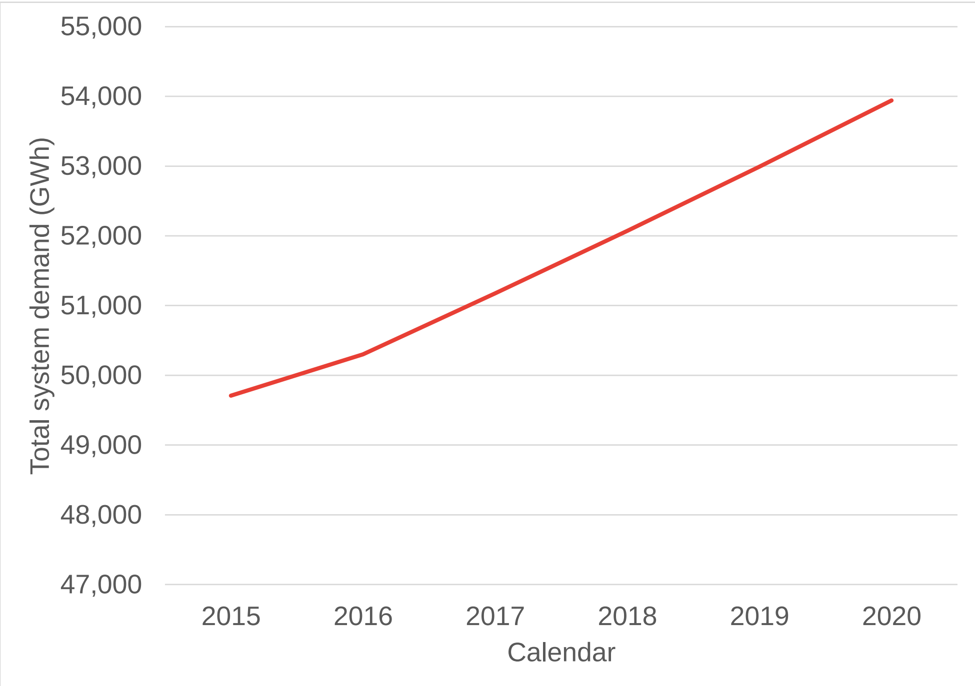
actual SWEM were not necessarily appropriate for our simplified regional/transmission structure assumed for modelling. For this reason, Frontier derived a set of calibrated impedances which were calibrated to generate flows which were more consistent with historical outcomes and thus more suitable to include in the forward period modelling.

Demand

Demand forecasts

The EMA provided Frontier with a series of annual total system demand and maximum demand forecasts out to 2020, as shown in Figure 11.

Figure 11: Demand forecast (GWh, total system demand)



Source: EMA

Since all modelling performed is conducted on a 'NEMS Cleared' basis[90], Frontier converted these figures to a NEMS Cleared Demand basis by adjusting for Generation Registered Facility (GSF) auxiliary losses and Generation Settlement Facility (GSF) generation (and associated auxiliary losses), where auxiliary losses were calculated as the volume weighted average GFR auxiliary losses for 2015.

Demand points

There is a computational trade-off between the resolution of demand and other areas of modelling focus. Rather than modelling every half-hour of the year, which would be very computationally intensive, we model a representation of the demand duration curve. This is accomplished through the following:

- We obtain historic 2015 half hourly demand for each subregion using load distribution information provided by the EMA.
- Hierarchical clustering methods are then used to determine a representative set of demand points by grouping together half hours of similar levels of demand across regions. Frontier has chosen to model 150 demand points per year, with each demand point containing demand information for each subregion in the analysis.
- These representative demand points are weighted to ensure that the full 17,520 half-hours of the year are captured.
- For each demand point, the average demand in each subregion across all half hours in that demand point is taken to be the representative level of demand.
- We then normalise the calendar year 2015 demand to represent 1 GWh per annum, and in such a way that the load factor is unaffected. The intention of this step is to isolate the shape of half-hourly load in the historic year.
- Now that we have the shape of demand, we scale the shape upwards to meet total energy and peak demand forecasts for each year.
- This yields a final set of 150 demand points per year, with demand for each subregion, which match the total energy and peak demand forecasts provided.

90 NEMS cleared demand corresponds to gross system demand less GRF auxiliary losses and GSF generation/auxiliary losses.

A comparison of actual half hourly demand and our calculated demand points is shown in Figure 12 on a load duration basis.

Figure 12: Half hourly demand versus demand points

Source: Frontier Economics

Supply

In this section we present operating parameters for various unit types to form the supply side inputs used in SPARK.

Operating parameters

Table 10 contains a summary of operating parameters used for various unit types. F-class CCGT unit heat rate and auxiliary losses are obtained from the 2015/2016 final determination review of vesting contract price parameters, Expected Forced Outage Rate (EFOR) and Expected Planned Outage Rate (EPOR) have been obtained from Frontier's international database of operating parameters. E-class CCGT and 'old' class CCGT (older than E-class) parameters are based on adjusting F-class CCGT parameters for relative 'inefficiency' in line with Siemens and GE published data for different unit makes and models[91]. Parameters for Steam and OCGT units are also taken from Frontier's international database of operating parameters.

For bio-coal, waste and other non-CCGT/OCGT/steam units (essentially non-Genco units, excepting Tuaspring), we assume for the forward modelling period an output profile equal to these units' historic output profile in 2015. Since these units are not modelled as strategic units, this effectively corresponds to the amount of must-run capacity in each period for that unit. Further, as these units are simply assigned must run capacity in each period, operating parameters do not play any role in the scheduling of these plant and are thus irrelevant. Modelled must run capacity amounts to around 575MW out of a total 948MW of non-Genco capacity and a total of 13,488MW non-GSF capacity, in gross terms.

Table 10: Operating parameters for various unit types (Note: Parameters in respect of E-Class CCGTs not shown here to ensure confidentiality)

	Heat Rate	Aux Losses	EFOR	EPOR	SRMC	Fuel
Units	*Gross, GJ/MWh*	*%*	*%*	*%*	*Gross, $/MWh, 2015*	*Type*
CCGT_F	6.7	2.9%	3.6%	6.7%	$76.52	Gas
CCGT_old	7.9	3.4%	4.3%	7.9%	$90.71	Gas
Steam	13.0	8.0%	4.0%	10.0%	$133.14	HSFO
OCGT	11.1	3.0%	4.3%	4.0%	$174.81	Diesel

Source: Frontier Economics

Fuel costs

LNG, PNG, Diesel and HSFO fuel cost estimates for 2015 were provided to Frontier by the EMA. These estimates were then escalated in real terms using World Bank commodities price forecasts for LNG and Crude Oil according to

91 See: http://www.energy.siemens.com/hq/en/fossil-power-generation/gas-turbines/, https://powergen.gepower.com/resources/tools/product-comparison/heavy-duty-gas-turbines.html

the schedule in Table 11. LNG and PNG prices were escalated at the LNG Japan index, while Diesel and HSFO costs were escalated using the Crude Oil index.

Table 11: Commodity indices, real 2015

Index	Relevant Fuels	2015	2016	2017	2018	2019	2020
LNG, Japan	LNG, PNG	1.00	0.80	0.81	0.82	0.83	0.84
Crude Oil*	Diesel, HSFO	1.00	0.72	0.91	0.96	1.01	1.07

Source: World Bank, (Jan 2016), Commodity Markets Outlook

**Crude oil is the average of Brent, Dubai and WTI prices, equally weighted*

Generation entry and exit

Frontier has not conducted any long term investment pattern analysis for either task and therefore has not included any future investment or retirement of plant beyond that for which public information has been released. Generation entry thus includes the entry of Tuaspring in early 2016 and the entry of SRC (2 x 42MW, 1 x 2MW) and EXXONMobil (2 x 47MW) units in early 2017. No generation exit has been scheduled in the modelling.

Other constraints

In addition to any applicable flow constraints across the modelled notional interconnectors, Frontier also includes constraints relating to reserves and take or pay gas arrangements.

Ancillary services

We have implemented a set of co-optimised ancillary service constraints in *SPARK*, consistent with the 'runway' approach used in the MCE.

Demand for ancillary services has been taken as the sum of the primary, secondary and regulation services on a half hourly basis, which is then averaged across all half hours within each demand point.

Supply is taken as the registered capacity for each service by generating unit, adjusted for auxiliary losses. Contingency services have not been included as these events occur over a longer timeframe, which is inconsistent with our demand point approach to modelling.

Take or pay (TOP) gas arrangements

Frontier has included minimum production profiles for generator portfolios in accordance with their take or pay arrangements, as per information provided by the EMA.

Contracts

When deciding how best to represent Gencos contract position it was necessary to keep in mind that the studies are predominantly related to the vesting level and changes to the vesting contract scheme design; thus a methodology which allows us to easily change these parameters to account for differences between model scenarios is ideal.

In this light, it was determined that the Gencos net contract position would be modelled as the sum of:

- (Add) Genco retail position: Historical information was provided by the EMA to Frontier on a half hourly basis. Frontier then adjusted Gencos retail position in line with energy demand growth for each calendar year in the forward period.
- (Add) Vesting quantity: The vesting quantity each period is determined as the average load (MW) per period by calendar year (using the demand forecasts provided) multiplied by the relevant vesting level based on which day types/period types constitute the demand point (i.e. what day types/period types are the half hours which make up each demand point). This quantity is then smeared across generators according a particular allocation method, for example, market share of total capacity or market share of effective (CCGT+OCGT) capacity. If the allocated contract quantity for any generator is not sufficient to meet their LNG vesting quantity, the generators vesting contract quantity will be set at LNG quantity which is flat across all period and day types.
- (Subtract) Vesting credits: The vesting hedge proportion for each day type/period type is the percentage of contestable load that is vested[92]. This is multiplied by the Genco's retail position (a measure of CC load) in each half hour to form a proxy for the vesting credits.

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92 The VHP is calculated as $\max(VCL - NCC\ load\ proportion, 0) / CC\ load\ proportion$, as per the EMA's procedures for calculating the components of the vesting contracts.

- (Add) Tendered unvested MSSL load contracts: Where we include the tendering of MSSL load to Gencos we have smeared the difference between the MSSL load and vesting quantities (by day type and period type), the unhedged MSSL load, across the Gencos according to a particular allocation method, for example, effective (CCGT + OCGT) capacity.

Thus the Gencos net contract position becomes:

$$NCP_i = RetailLoad_i - VestingCredits_i + VestingQty_i + NCCTender_i$$

Bidding

Under the game theoretic approach of SPARK, we define the game in the NEMS in terms of the big 6 Gencos plus Tuaspring CCGT plant as strategic players with a menu of strategies. Non-CCGT plant are assumed to be non-strategic units who have fixed strategies and therefore bid in 100% of their capacity adjusted for EPOR (and EFOR in the average derating modelling approach) and if the plant are non-CCGT/Steam/OCGT they are further subject to their outage profile (and thus dispatch for these plant is effectively capped at the assumed outage profile). Non-strategic players are unresponsive to the behaviour of other players.

Cournot bidding is modelled as physical withdrawal, so that, for example, a Q100/Q90/Q80 strategy set represents 100%, 90% and 80% offers of player's aggregate capacity at SRMC prices. Recall that physical withholding is the equivalent to economic withholding in terms of incentives[93].

There is a trade-off between computational burden and the range/resolution of bidding strategy sets. Range here refers to the max bid quantity vs. the minimum bid quantity and resolution refers to the number of steps between min and max bid quantities. After extensive sensitivity testing[94], Frontier believes that a reasonable trade-off is to model three possible strategies for each of the strategic players, excepting the Sembcorp CCP3 behind the Tembusu constraint and Tuaspring, which have been assigned two possible bidding strategies. Assigning only two strategies to these units, rather than three, more than halves the computational burden (from 59,049 possible combinations to 26,244 possible

93 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.317.

94 Sensitivity testing here referred to the process of modelling, for the calibration year, many different sets of bidding strategy ranges/resolutions for different participants (whilst keeping in mind potential computational burden) and aligning these modelled outcomes with observed historical outcomes.

combinations), and sensitivity testing has indicated it is not necessary to assign as large a resolution to these units.

We have assumed a strategy set of Q100/Q80/Q60 for the big 6 Gencos and Q100/Q60 for Tuaspring and SembCCP3. This range of withdrawal (from 100% to 60% of capacity) is consistent with the physical operating range of these units and historically observed bidding behaviour. Allowing for an additional 80% strategy for most Gencos represents a trade-off between higher bidding resolution and the computational size of our overall analysis. Using this strategy set, we model 3,936,600 unique bidding combinations per annum, per modelling case – representing a large possible solution space.

Sensitivity testing indicated that this strategy set was appropriate and produced outcomes closely calibrated to those observed during 2015.

Generation outages

The task of reviewing potential new mechanisms to mitigate market power is essentially an exercise in *comparative statics*. That is, we are comparing a reference case to alternative cases that include different market power mechanisms. Whilst absolute outcomes in the reference case are important, the study is focused on the difference between cases. This allows for some simplifying assumptions that would not be as appropriate if absolute forecasts were the focus of the study; in this study we assume that a generating unit's registered capacity is derated on an annual average basis not only for expected planned maintenance outages but also expected forced outages.

Conversely, setting the VCL requires accurately forecasting *absolute* price outcomes in the NEMS and a more complete treatment of possible price effects due to changes in the vesting level. This requires an extension to the modelling performed in the review of potential new market power mitigation mechanisms. Specifically, for setting the VCL we have incorporated generator forced outages on a stochastic basis as opposed to the average derating method mentioned above. Such an inclusion significantly increases the modelling task intensity and time required, which is why we have reserved such analysis to the task of setting the VCL only.

Incorporating stochastic unit outages into the *SPARK* modelling involves the following steps:

- For each unit in each demand point for the base year, we randomly determine whether there is an outage on that unit by sampling from a Bernoulli distribution with probability of success equal to the historical EFOR. This is equivalent to assuming full unit forced outages on a random basis. Partial unit forced outages have not been considered in our approach.

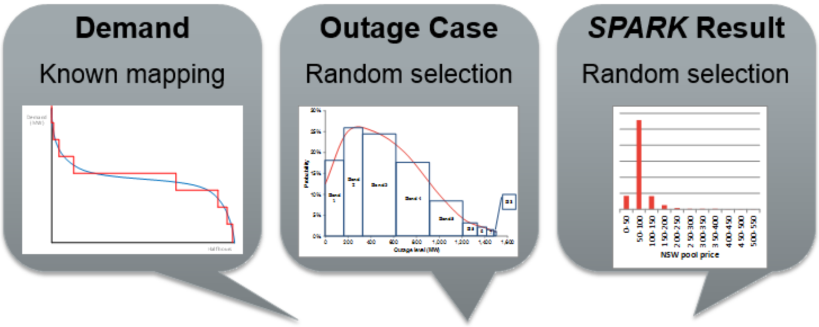
- We repeat this calculation 100 times to form a Monte Carlo simulation and obtain distributions of the outages.
- For each demand point, we rank the simulations in order of total outage capacity from highest to lowest (i.e. simulation 14 may have seven units out amounting to a total capacity of 2000MW, whereas simulation 86 might only have two units out with a total of 500MW outage capacity). We then take the simulations corresponding to the 100th (highest), 90th, 70th, 50th and 30th percentile of total outage capacity (call these the 'outage cases'). We skew the chosen percentiles towards the top end of the outage distribution since these cases would have the larger price impacts and are therefore more important to consider.
- Combining these calculations across all demand points, we obtain outage profiles representing each of the outage cases. Note that from this we can obtain a simulated EFOR (across the weighted outage cases) that was compared with historical EFOR to ensure that they were broadly aligned and that there was no systematic bias in assumed outage profiles.
- These outage profiles are repeated for each calendar year in the forward period.

For a single scenario, we therefore have five corresponding outage cases (five *SPARK* runs).

Once the *SPARK* models have been run, we once again randomly sample from the modelled results to obtain final estimates of the outcomes. The process is illustrated in Figure 13 and described below:

- Each of the 17520 half hours in a given year are mapped to a demand point according to the clustering methodology described in the section above. We randomly choose an outage case from which to sample modelled outcomes.
  - Each outage case does not have equal likelihood of being chosen, rather, each outage case is chosen to represent the underlying distribution of outages in our simulation.
- Once the outage case has been selected for that half hour, we then randomly sample a single equilibria from the Nash Equilibria of its associated demand point from that outage case. In doing this, we assume that all Nash Equilibria are equally likely.
- Repeating this process for each of the 17,520 half hours per year produces a simulated 'year' of pricing outcomes from which a range of values are recorded (such as the annual average price).
- We repeat this process to generate 100 simulated years to form a distribution of pricing outcomes, and compute summary statistics based on this derived distribution.

Figure 13: Obtaining estimates from stochastic outage case modelling



Year	Day	Half Hour	Step 1: Demand Point Mapping	Step 2: Select Outage Case	Step 3: Select Equilibria
2017	1	1	1	70th Percentile	64
2017	1	1	2	30th Percentile	15
2017	1	1	2	100th Percentile	7
2017	1	1	3	30th Percentile	3
...	...	...	...	...	...
...	...	...	...	...	...
2018	365	48	149	50th Percentile	18

This process is repeated 100 of times to generate distributions of pricing outcomes

Source: Frontier Economics

Appendix D – Market modelling calibration results

In this section we present the calibration results for the reference case. These results are based on a set of modelling inputs which were deemed most appropriate in light of the calibration process and sensitivity tests performed by Frontier. Details of sensitivity tests and calibration processes for specific inputs can be found in Appendix C – Market modelling inputs.

Comments on the draft report

Participants, most notably Senoko, comment that our modelling approach systematically underestimated forecast pool prices as evidenced by our modelled 2015 prices being below actual prices observed in the market. Our original draft report discussed how we have not included a number of actual constraints and outages that occurred in practice over 2015, and that this exclusion explains the difference in the calibration process. Moreover, our chosen modelling sensitivities and the comparative static nature of the analysis further ensure that our recommendations rest on reliable modelling forecasts.

No comments were received regarding this section in the revised report.

Backcasting versus calibration

It is first important to be wary of the purpose of calibration and, in this light, distinguish the calibration process from an exercise in backcasting.

As mentioned at various points throughout Appendix C – Market modelling inputs, is that *SPARK* operates on a simplified version of the NEMS; it assumes a simplified regional representation with high level transmission constraints. As we will see shortly, and as one would suspect, these simplified modelling assumptions are the main contribution to discrepancies between modelled outcomes and historical actuals. Absent full constraint and nodal demand information, our aim for the forward looking *SPARK* modelling is therefore not to necessarily find parameters which replicate historical outcomes exactly (backcasting), since we expect they should not be able to be very closely replicated with our simplifying assumptions. Rather, we determine the most appropriate set of information for future periods being *guided* by outcomes which are reasonably aligned to historical outcomes; that is, a calibration process.

Average derating approach SPARK modelling

Figure 14 presents *SPARK* modelling annual USEP results for the calibration year and forward modelling period for the reference case, using an average derating approach for forced outages.

We present these results along with forecast indices of demand, fuel and take or pay gas arrangements. Recalling that in the reference case, the VCL is held constant at 25% for all periods, these forecast indices help to provide insight as to why we observe the level change in prices over the years.

- Both the steep decline in LNG gas prices, teamed with an increase in TOP lead to a substantial reduction in modelled prices between 2015 ($85.26/MWh) and 2017 ($66.70/MWh). This drop is in line with the drop between 2015 actuals and the 2017 SGX price[95]
- Beyond 2017, average annual prices rise in line with increasing fuel costs, demand and easing TOP levels
- Modelled average annual USEP for 2015 ($85.26/MWh) is lower than historical actual ($95.97/MWh), which we attribute to the simplified regional structure, assumptions around nodal demand, our adoption of stylised bidding options as opposed to actual bids and the assumption of limited transmission constraint information and our decision to 'look through' some transient existing constraints in 2015[96] as this would have unnecessarily complicated our forward looking study and limited our range of analysis in the forward period

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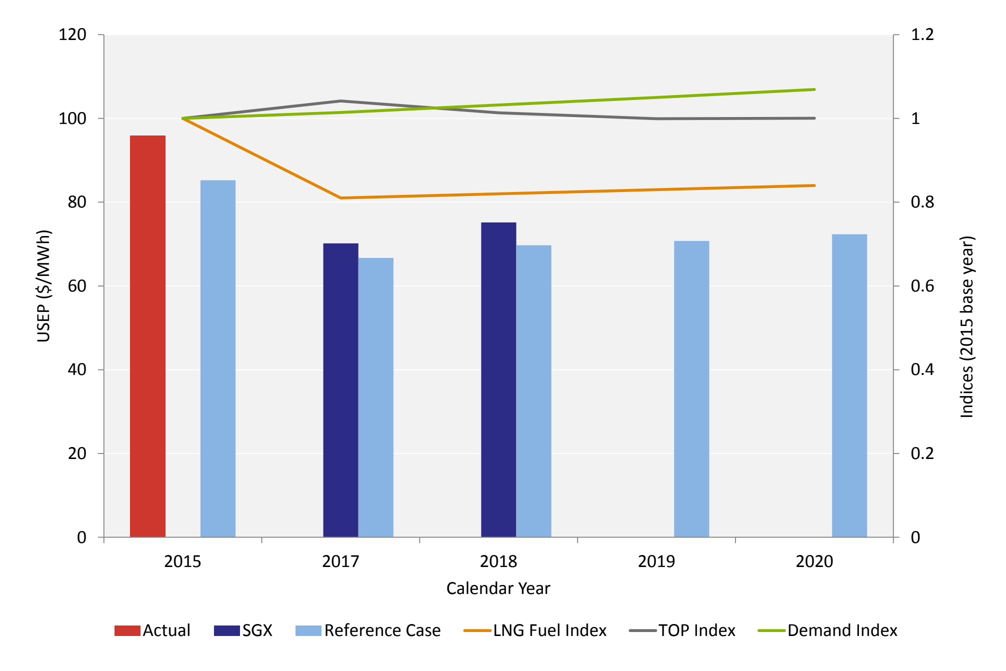
95 Indeed the SGX price is lower than our modelled price, perhaps due to the market discounting gas prices more than the World Bank commodities forecast for LNG, which we have utilised in our modelling.

96 For example, constraint B applied for the majority of 2015, and was then superseded by constraint C. Since constraint B is not relevant to the forward period modelling, for which the studies are focussed, it has been excluded from the analysis.

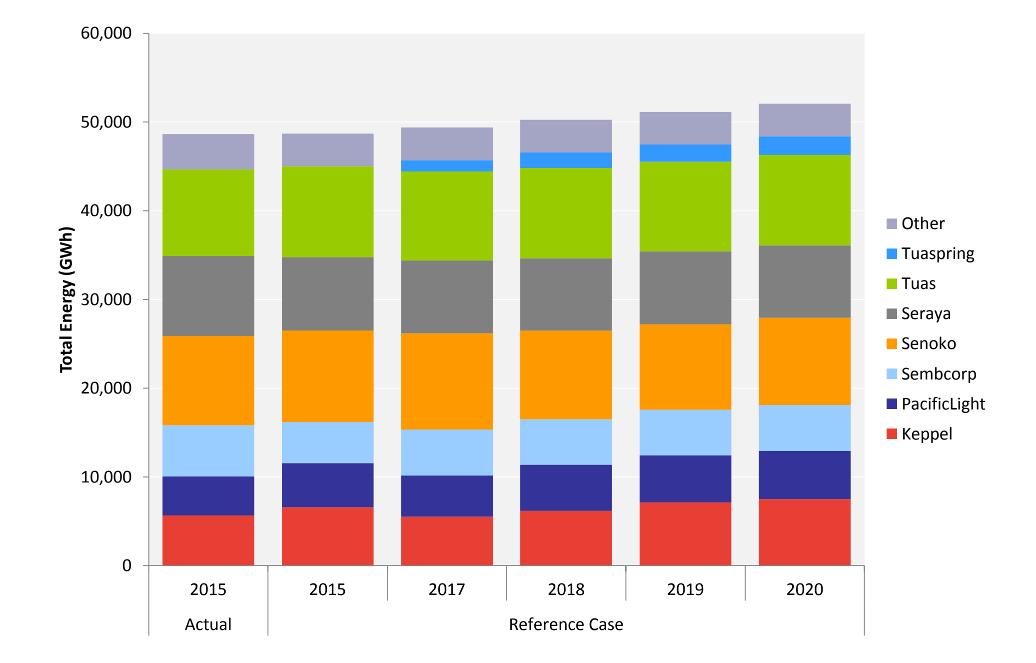
Figure 14: Reference case annual average USEP, calibration year and forward period



Source: Frontier Economics SPARK market modelling, estimates based on average derate approach

Figure 15 presents annual total energy dispatched by portfolio for the calibration year and forward period for the reference case, using an average derating approach for forced outages. We can see that modelled dispatch outcomes are reasonably in line with historical dispatch outcomes, and total energy grows at the rate of demand growth. There are some discrepancies in dispatch, with PacificLight and Keppel slightly over dispatching at the expense of Sembcorp on Jurong Island, and Tuas and Senoko slightly over dispatching at the expense of Seraya and Others.

Figure 15: Reference case annual total energy (GWh), calibration year and forward period, average derate approach



Source: Frontier Economics SPARK market modelling

Stochastic outage SPARK modelling

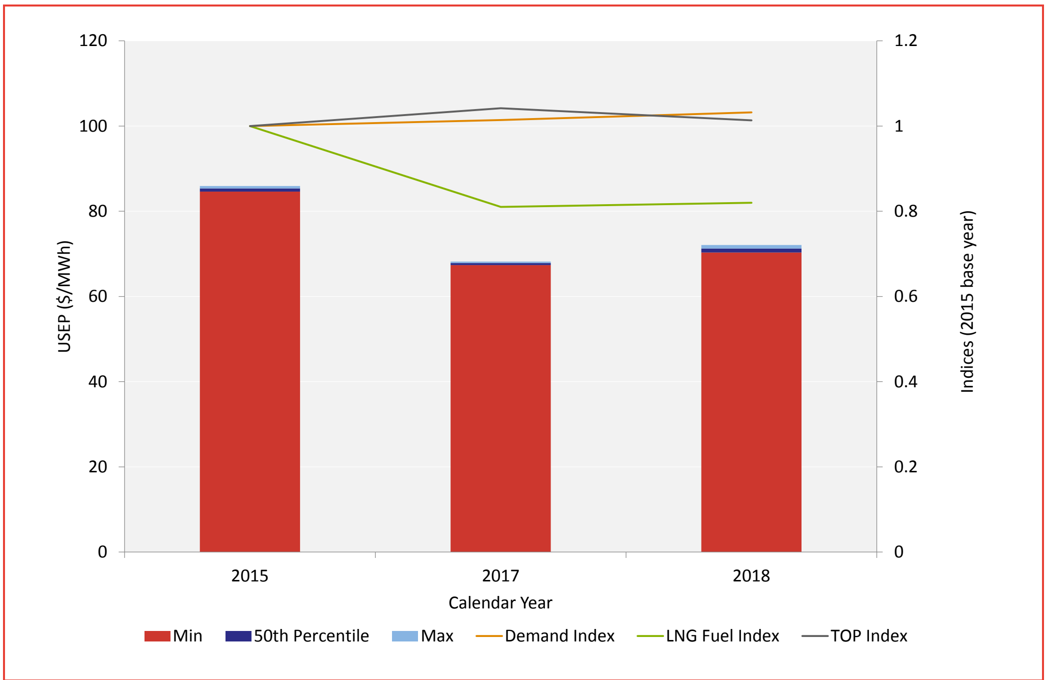
Figure 16 illustrates the distribution of price outcomes of annual average USEP for the calibration year and VCL review periods for the reference case, using a stochastic outage approach for forced generator outages. We present the results as a series of stacked bars representing the minimum, 50th percentile and Max price outcomes, along with line series representing various indices.

Compared to the average derate approach we observe that:

- The levels of prices in the stochastic outage modelling cases are slightly higher in each of the years
  - The 50th percentile estimates for the stochastic outage modelling are $85.35/MWh, $67.86/MWh and $71.24/MWh for 2015, 2017 and 2018 respectively, compared with $85.26/MWh, $66.70/MWh and $69.73/MWh for the average derate case
  - Price increases are very minor, reflective of the market conditions in the NEMS. That is, the market oversupply and TOP arrangements lead to small differences between the average derating and outage approach, since even in times of relatively higher system outages, there is still much excess supply that can easily meet demand.
- The distribution of prices across the years moves in a similar fashion to that observed in the average derating approach; prices decline in 2017 in line with

increased TOP levels and the drop in fuel prices, while increasing in 2018 in line with slight fuel price recovery and demand growth

Figure 16: Reference case annual average USEP distributions, calibration year and VCL review years, stochastic outage approach



Source: Frontier Economics SPARK market modelling

Appendix E – Quantitative analysis results

This appendix presents the quantitative analysis which supports the recommendations throughout the report. It is structured in such a way that corresponds to the order in which recommendations appear.

Comments on the draft report

Participants comment on the relativities between modelled prices and the comparable LRMC values reported in our draft report and the subsequent addendum that was released on this issue. This issue is a consequence of the difference between the confidential fuel cost used to calculate SRMCs used in the modelling (which drive the level of forecast prices) and the different fuel costs values used in estimating a comparable LRMC value (which is independent of our market modelling). We have attempted to clarify this issue in the sections below.

Ultimately, we do not see any issue with our modelling approach or recommendations as a result of updating the value of our comparable LRMC estimate.

No comments were received regarding this section in the revised report.

Setting the VCL for 2017 and 2018

In this section we discuss the *SPARK* market modelling results which inform the setting of the VCL for 2017 and 2018. The scope of analysis included the following:

- A base case scenario, which involved the measurement of price distribution effects when increasing or decreasing the VCL from the current VCL of 25%
  - The base case scenario modelling included both a case for where unvested MSSL load remained unhedged and a case where it was assumed to be prudently hedged
- A bidding sensitivity scenario, where we assumed that both steam and OCGT units were offered into the market at $350/MWh which is roughly equivalent to an OCGT unit with double fuel costs

    - This scenario was similarly modelled with an unhedged unvested NCC and a hedged unvested NCC case

- A supply-demand sensitivity scenario, where we tightened supply demand conditions by assuming the growth rate for energy/peak demand is doubled and that around half of the steam units are removed from the market[97]

    - We modelled this scenario with only the hedged unvested NCC case

All scenarios were conducted using the stochastic outage modelling approach, as described in Appendix C – Market modelling inputs. Further, in cases where unvested MSSL load is hedged, it is smeared across the big 6 Gencos according to their market share of effective (OCGT + CCGT) capacity.

For each of the scenarios we present results in a series of box plots. These box plots represent the underlying distribution of average annual USEP outcomes across the Monte Carlo simulation, as described in Appendix C – Market modelling inputs. The box displays the 25th, 50th (median) and 75th percentiles, while the whiskers represent the minimum and maximum across simulations.

We generally present results across a range of five vesting levels; LNG vesting, 20%, 25%, 30% and 35%, however, due to the onerous modelling task when stochastic outages are included, for some sensitivities we have omitted the raise VCL cases (30% and 35%).

Assumed fuel costs, SRMC, modelled prices and LRMC

It is worth distinguishing between a range of modelling inputs, outputs and post-modelling comparators:

- **Fuel costs** that influenced the modelling were provided on a confidential basis by the EMA.
- For each unit in the system, an **SRMC** was calculated using the assumed fuel price, heat rate and variable operating and maintenance cost. In the modelling, units are assumed to offer into the market at this calculated SRMC. Other things equal, if demand is sufficient to lead to a given unit

97 This corresponded to removing 3 x Seraya steam units and 1 x Senoko steam unit. Tuas' steam unit was retained in the market.

being dispatched, the model will forecast a price that is equivalent to the most expensive dispatched units' SRMC (the marginal unit).[98]

- **Modelled prices** reflect calculated SRMCs, which in turn reflect assumed fuel costs.
- Modelled prices are then compared to **LRMC** estimates for 2017 and 2018, which were calculated to be $129/MWh and $130/MWh, respectively (see Box 2 below). Importantly, in our analysis the fuel cost used to calculate LRMC *does not* match the confidential fuel cost used to calculate SRMC (which in turn drives modelled price outcomes).

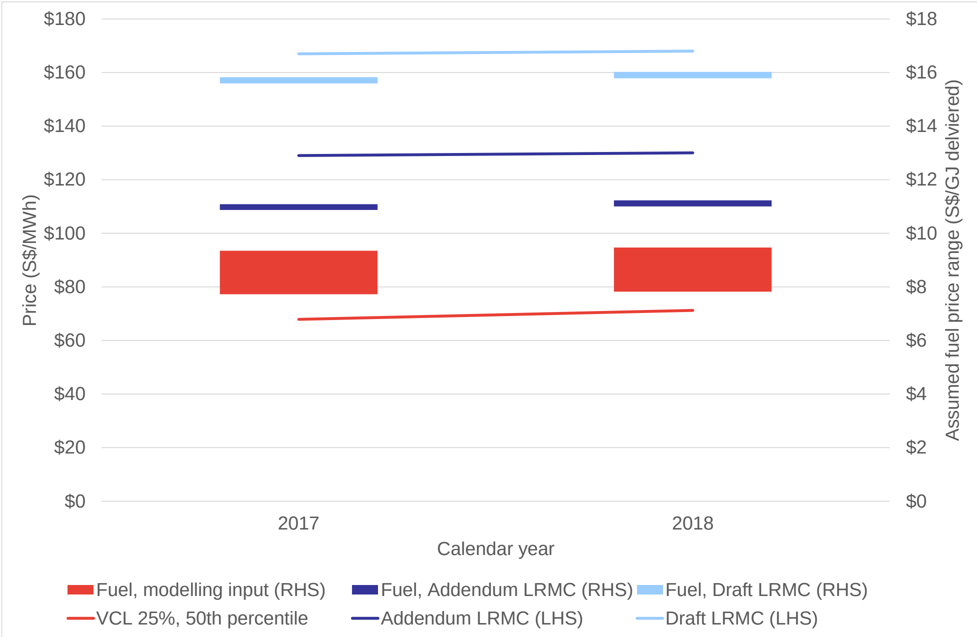
In our draft report we used the EMA's estimate of LRMC (and associated fuel costs) that were reported as of 2014.[99] This LRMC estimate reflected contemporary gas prices and was on the order of $170/MWh. The fuel costs used to calculate SRMC in our modelling was based on 2015 data and reflected the material reduction in fuel prices that occurred post-2014. This issue – the usage of correct gas cost data for calculating SRMC and modelled prices but obsolete gas cost data for calculating comparator LRMC estimates – was corrected via an addendum to our draft report. This correction involved updating the fuel costs used to calculate LRMC to reflect the actual fuel costs used to set quarterly vesting prices over 2015 (see Box 2 below). This reduced the LRMC estimate to $129/MWh and $130/MWh in 2017 and 2018 respectively. Modelled prices and LRMC estimates are calculated independently, so this correction had no bearing on the market modelling itself.

These differences between input fuel costs, modelled prices and LRMC estimates are shown in Figure 17 below. Input fuel costs are presented as a range to ensure confidentiality of the inputs is maintained.

98 The only major exception to this outcome is instances where assumed gas TOP levels lead to a unit being dispatched to meet TOP even when prices are below that unit's SRMC.

99 Reflecting a pipeline gas price of S$19.44/GJ and regasified LNG price of S$20.24/GJ, see EMA, *Review of Vesting Contract Price Parameters for the Period 1 Jan 2015 to 31 Dec 2016, Final Determination Paper*, 22 September 2014, p8.

Figure 17: Fuel costs, modelled prices and LRMC



Source: Frontier Economics

We note that there is still a difference between the fuel cost assumed in the modelling and the (higher) fuel cost used in the comparative LRMC calculation. This difference is explained by the assumption of a 'pure' pipeline gas cost in the modelling, whereas the fuel cost used in the LRMC calculation represented a (higher) blended price).

Our recommendation on VCL is conditional on the unvested MSSL load being prudently hedged. When unvested MSSL load is prudently hedged, our modelling forecasts pool prices around $70/MWh for the base case and less than $100/MWh for the sensitivity cases. These forecasts are substantially less than either the original or updated comparative LRMC, and indeed are less than any LRMC that assumed the same fuel price as the modelling (which remain significantly above $100/MWh). In the cases where the unvested MSSL load is not hedged, we see forecast prices higher than the updated LRMC estimated in the Bidding Sensitivity case for 2018 only.

Given that our recommendation is that there is scope to reduce VCL subject to prudently hedging the unvested MSSL load, our conclusions and recommendations therefore remain unchanged. We further note that changing the assumed input fuel cost in our modelling would act to lift the level of prices in all cases and for all modelled VCL values, but would not materially impact on the relativities between cases. Our recommendations are based on the relative differences between assumed vesting contract levels and the various market power mechanisms.

Box 1: Estimating LRMC for 2017 and 2018

We calculate the (real) Balance Vesting Price as the sum of a non-fuel costs component and a fuel costs component. These are estimated as follows:

Non Fuel: All previous non-fuel LRMC parameters in the vesting price parameters final determination for 2015/16 are taken as given. This effectively means that the 'non-fuel' component of LRMC is assumed to remain at $46.25 (real) for 2017/2018.

Fuel: To obtain the fuel cost estimate, we have taken the average of 2015 quarterly vesting prices and subtracted the non-fuel component; leaving an estimate of fuel costs for calendar year 2015. We then escalate this fuel component using the real LNG price index obtained from the world bank 2016 commodity markets outlook to obtain the real (2015) fuel costs for 2017 and 2018.

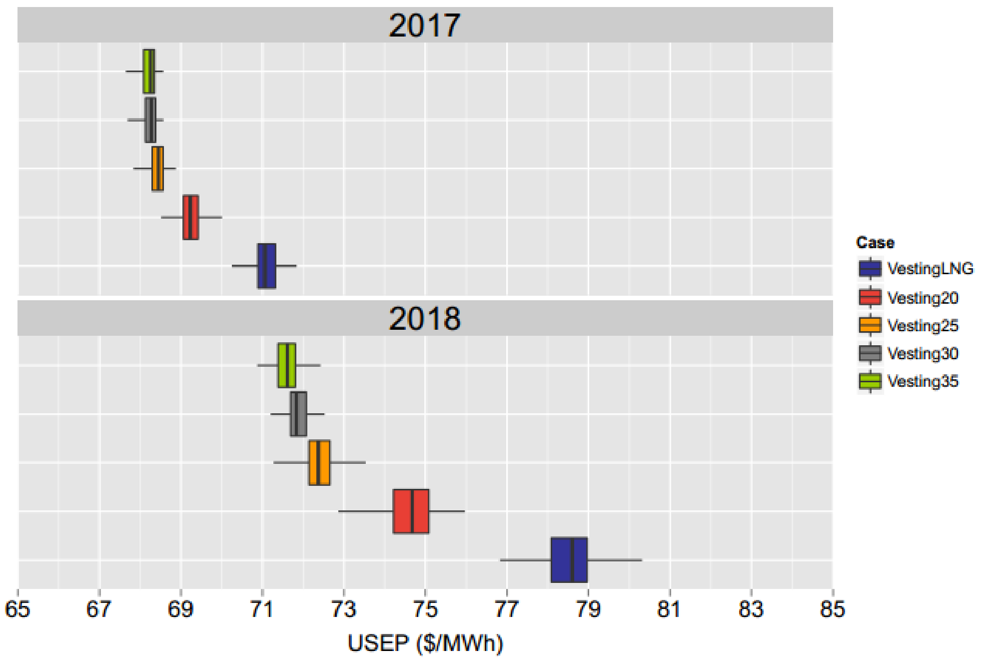
We estimate the LRMC for 2017 to be $129/MWh and the LRMC for 2018 to be $130/MWh

Reference case results

Figure 18 displays average annual USEP distributions for the reference case with unvested MSSL load unhedged, across the tested range of vesting levels. We see that as the vesting level is reduced both the volatility and level of prices increases, for both calendar year 2017 and 2018. The most substantial increases in price occur between decreasing the VCL from 25% to 20% and from 20% to LNG vesting. Recalling Figure 5, these results are unsurprising, since where the VCL drops below the MSSL load proportion, generators gain increasingly greater pool exposure due to reduced net contract positions and therefore have more incentive to exercise market power to increase prices in the wholesale market. This is felt most largely where vesting levels are dropped to LNG vesting level.

We do note, however, that prices do not near LRMC for either 2017 or 2018, which are estimated to be approximately $129/MWh and $130/MWh respectively. Even where the VCL is reduced to LNG vesting, the maximum price simulated for 2018 was around $80.50/MWh, which is substantially lower than LRMC.

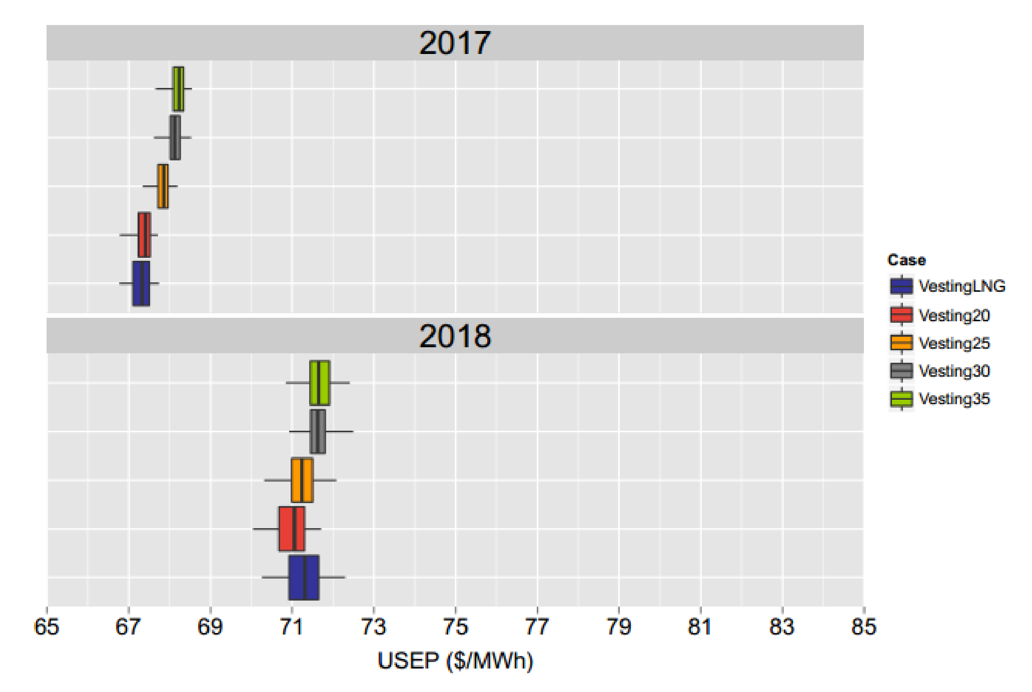
Figure 18: Base case, 2017/18 annual USEP price distributions, various VCL, unvested MSSL load unhedged



Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices – **note horizontal scale changes**

Figure 19 displays results for the reference case with unvested MSSL load prudently hedged and assigned to the big 6 Gencos based on market share of effective (CCGT + OCGT) capacity. We observe substantially different price outcomes under this approach, with increases in the vesting level leading to overall small price *reductions*. We consider this in light of the fact that MSSL load contracts have a different shape (that is, a small number of contracts during peak periods and more in shoulder and off-peak periods) and a different allocation method (on effective capacity share, rather than total capacity share at vesting start). Further, that the modelling task assumes a number of simplifying assumptions. Therefore, on balance, we believe the results indicate that prudently hedging MSSL load appears to be as effective as vesting contracts, under our base case assumptions.

Figure 19: Base case, 2017/18 annual USEP price distributions, various VCL, unvested MSSL load hedged



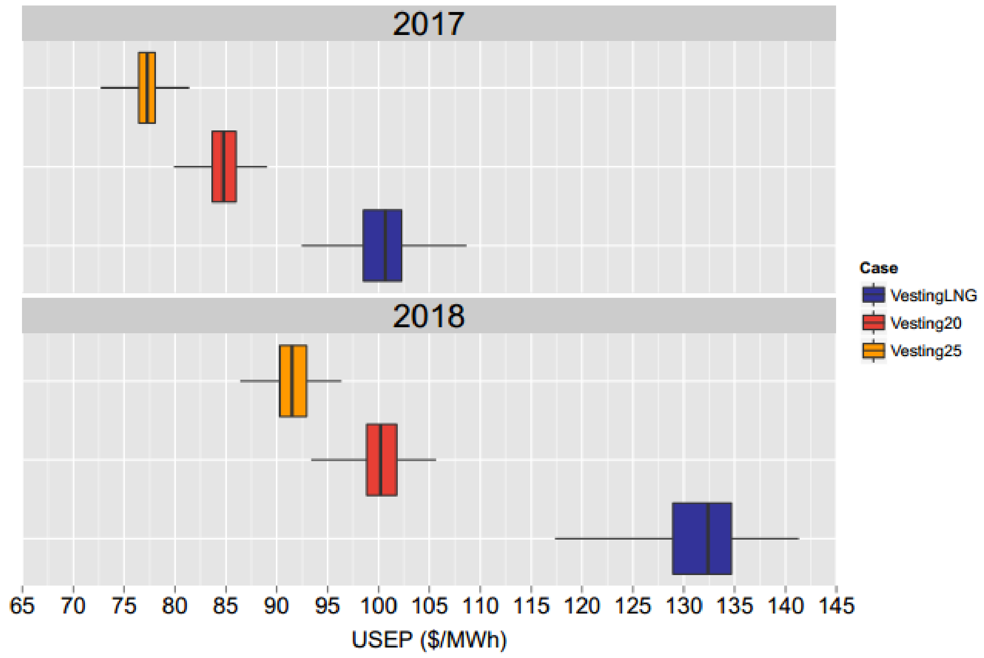
Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices – **note horizontal scale changes**

Bidding sensitivity results

Upon observing little negative consequences for lowering the VCL in the case where unvested MSSL load is prudently hedged, there may be an argument for lowering the VCL. However, in this section and the following, we consider some sensitivity modelling which indicates that reducing the VCL could lead to material increases in price.

Figure 20 presents the results for the bidding sensitivity case, where we assume that steam and OCGT plant bid into the market at $350/MWh (approximately the SRMC of an OCGT unit with double fuel costs), and that the unvested MSSL load remains unhedged. Price rises under this sensitivity are material; increasing by $24/MWh in 2017 and $30/MWh in 2018 when the vesting level is dropped from 25% to LNG vesting. Prices are only higher than LRMC for the Vesting LNG case in 2018.

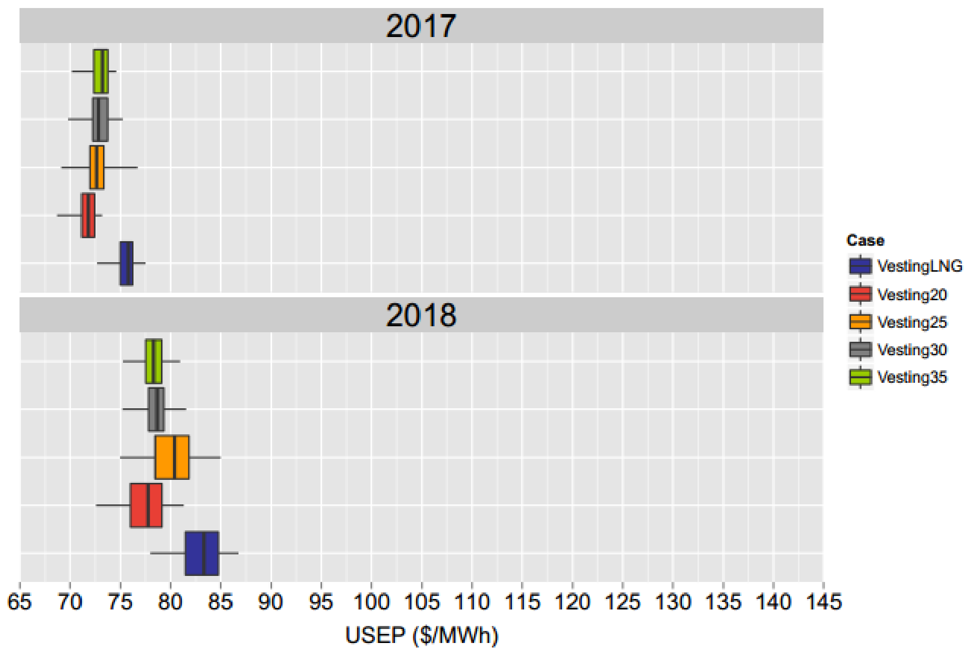
Figure 20: Bidding sensitivity case, 2017/18 annual USEP price distributions, various VCL, unvested MSSL load unhedged



Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices – **note horizontal scale changes**

Considering this case again, but with the unvested MSSL load prudently hedged, Figure 21 shows that lowering the VCL does not result in price increases for all vesting levels until LNG vesting level. That is, prudently hedging MSSL load offsets the VCL reductions until the VCL is lowered to LNG vesting, where we do observe a price rise in both years. Nevertheless, the price rise is still relatively small when moving from 25% VCL to LNG vesting (in the order of $3/MWh in both 2017 and 2018) compared to the case where unvested MSSL load remains unhedged.

Figure 21: Bidding sensitivity case, 2017/18 annual USEP price distributions, various VCL, unvested MSSL load hedged



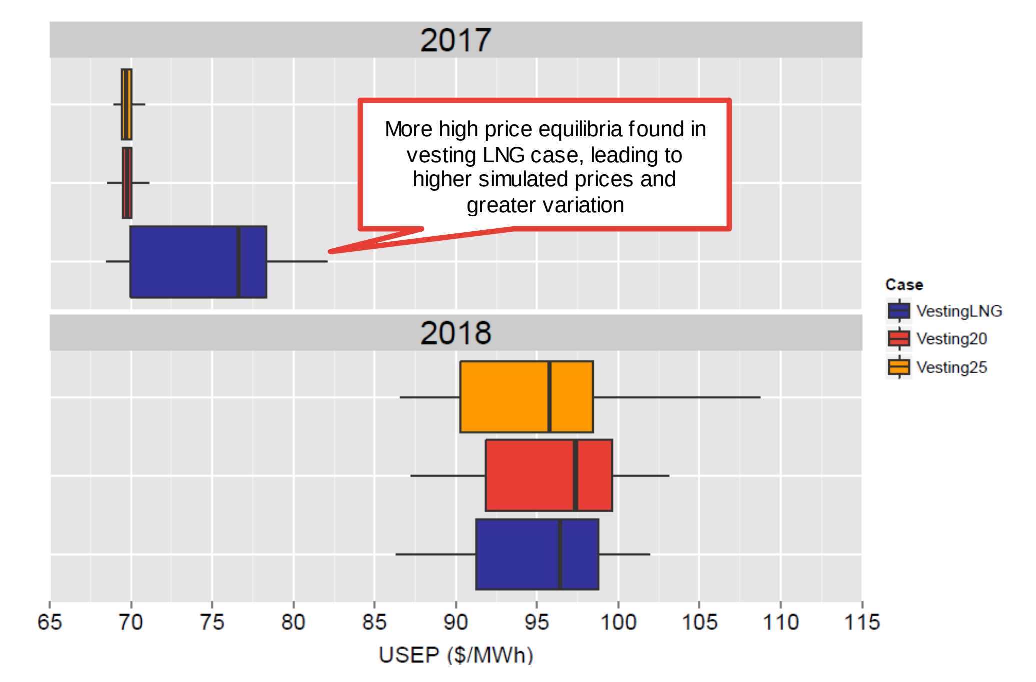
Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices – **note horizontal scale changes**

Supply-demand sensitivity results

Lastly, we conducted a sensitivity with tightened supply-demand conditions where we assumed the growth rate for peak/energy demand is doubled and half of the steam units are removed from the market. Due to computational constraints, we performed this sensitivity for the unvested MSSL load prudently hedged case only.

Figure 22 presents the results of this sensitivity. For 2017, with the VCL at 25% and 20%, levels of prices (around high $sixties/MWh) and volatility (around $1-2/MWh spread) are similar to the base case. Decreasing the VCL to LNG vesting results in a material increase in price (around $10/MWh) and a substantial increase in volatility. Comparatively, in 2018, the absolute level of prices for all VCL are much higher in the sensitivity compared with the base case (around $96/MWh vs. $71.5/MWh) and volatility at all VCLs is much higher. Further, there are no material price increases when decreasing the VCL, since the increased volatility and level of prices is shared across all VCL.

Figure 22: Supply demand case, 2017/18 annual USEP price distributions, various VCL, unvested MSSL load hedged

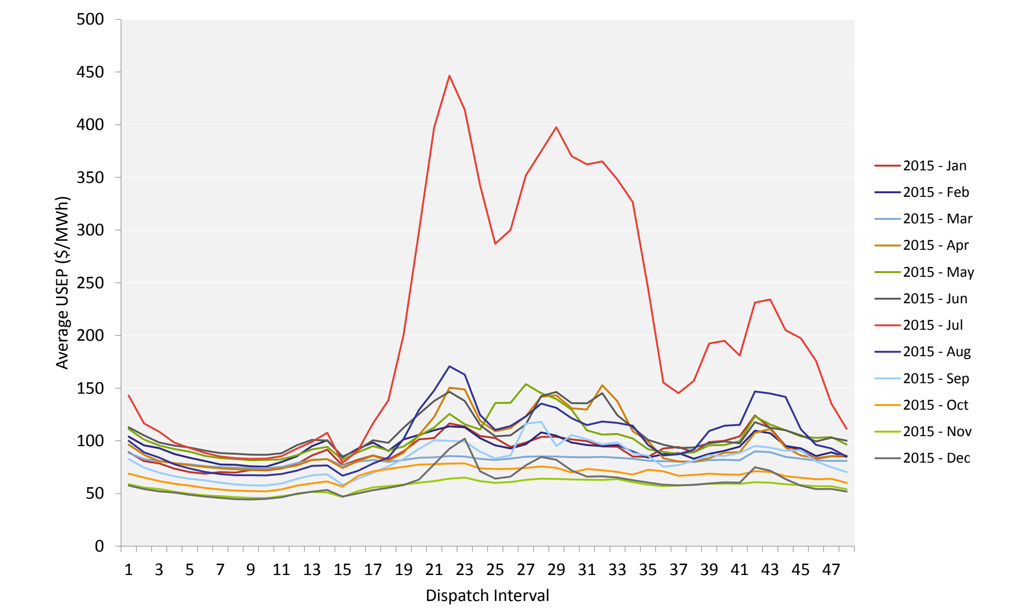


Source: Frontier Economics forecasts. Box and whisker plot shows maximum and minimum (whiskers) and 25th, 50th and 75th percentile (box) forecast prices – **note horizontal scale changes**

Historical SWEM prices

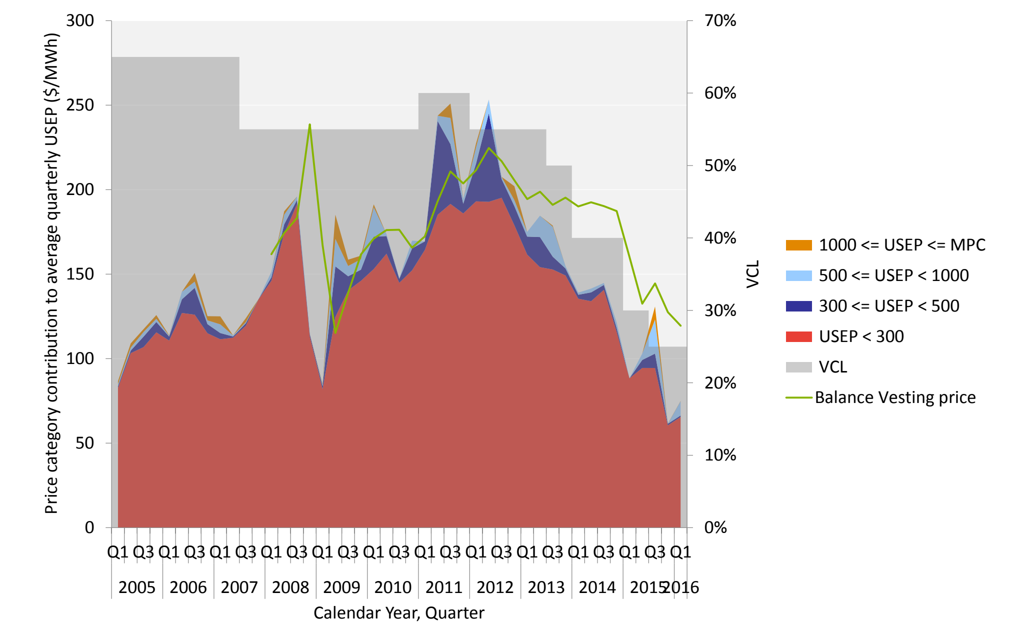
In recent times we have observed some higher price events; most noticeably events occurring in July 2015 as a result of a series of generator outages and October 2015, relating to a transmission congestion event (see Figure 23). However, these events don't seem to be unusual given the longer history of market prices. Figure 24 displays historical VCL (semi-transparent grey series) and Balance Vesting Price (line series) along with average quarterly spot price, where the contribution to the average quarterly price across different half hourly price bands is displayed as a stacked plot. Looking at these market prices over history, we observe two broad periods. From 2009 to 2012 supply-demand conditions were tighter and input fuel costs set a higher level for prices, this resulted in spot prices averaging above the vesting prices for the four year period. From 2013 to the present, with the entry of considerable new capacity on the back of LNG supplies and falling fuel costs, we see a drop in the level of prices, over this period spot prices have been well below prevailing vesting prices. Whilst the VCL would have impacted on these outcomes to some extent, we observe that price levels are primarily driven by wider market conditions regarding the supply demand balance and gas prices. Indeed, our market modelling sensitivity of tightened supply demand conditions suggests that if the supply demand balance is tighter, then the general level of prices shift upwards and, conditional on the unvested MSSL load being prudently hedged, there is no issue in regard to the exercise of market power against that higher level of prices, for various VCL.

Figure 23: Historical monthly average prices, by period



Source: Frontier Economics analysis of historical EMC data

Figure 24: Average quarterly price contribution, VCL and Balance Vesting Price



Source: Frontier Economics analysis of historical EMC data and MyPower Vesting Contract historical data

Box 2: Summary of results – Setting the VCL for 2017/2018

Base case:

- Leaving unvested MSSL load unhedged results in substantial price rises and increased volatility, though still not in the region of LRMC
- Prudently hedging unvested MSSL load appears to be as effective as vesting contracts, with no price increases observed when lowering the VCL

This suggests there is scope for lowering the VCL, however…

Bidding sensitivity case:

- Where unvested MSSL load is hedged, we observe material price rises. Modelled prices are higher than estimated LRMC for the Vesting LNG case in 2018.
- Upon prudently hedging the unvested MSSL load, we observe no material price increases when dropping the VCL to 20%, however we do observe minor price increases when further dropping the VCL to LNG vesting

Supply demand sensitivity case:

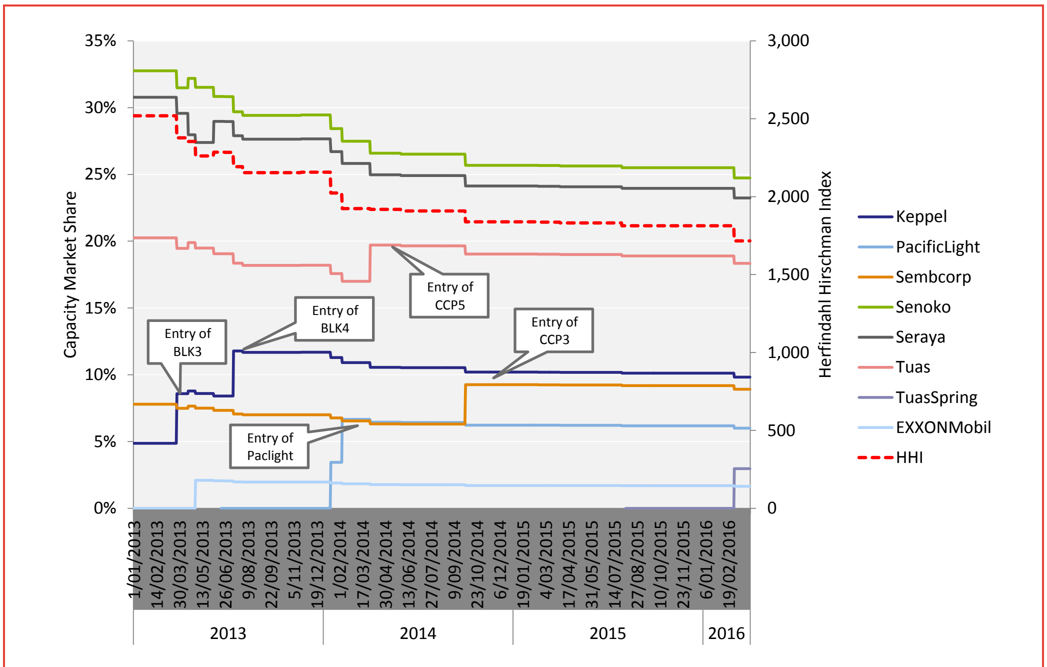
- 2017 - Where unvested MSSL load is prudently hedged, we observe little price difference when reducing the VCL from 25% to 20%, however, a material but relatively moderate price rise and increase in volatility where the VCL is dropped from 20% to LNG vesting
- 2018 – There are no material price changes from reducing the VCL; prices are higher and more volatile across all VCL

Concentration cap

Figure 25 shows a simple historical analysis of market share of capacity and HHI from January 2013 to December 2015 on the basis of registered capacity. From this chart, we can draw a few insights:

- Seraya and Senoko are the two largest players.
- Their market share has been declining since 2013, along with the introduction of Pacific light, two large Keppel units, a large Sembcorp unit and a large Tuas unit.
- The HHI has been decreasing over time, indicating that the market is becoming less concentrated.
- The introduction of PacificLight, Sembcorp and Keppel units all lead to a corresponding reduction in the HHI. Interestingly, the introduction of Tuas CCP5 unit neither increases nor decreases the HHI due to its comparative size in the market.
- With the introduction of Tuaspring, Senoko's market share drops below 25%, so that no single participant has a market share greater than 25%. Further, the HHI drops below 1800, to 1716, which is out of the FERC range of 'highly concentrated'. Similar outcomes occur with regard to licenced capacity (as opposed to registered).

Figure 25: Historical market share and HHI



Source: Frontier Economics historical analysis of EMC registered capacity information

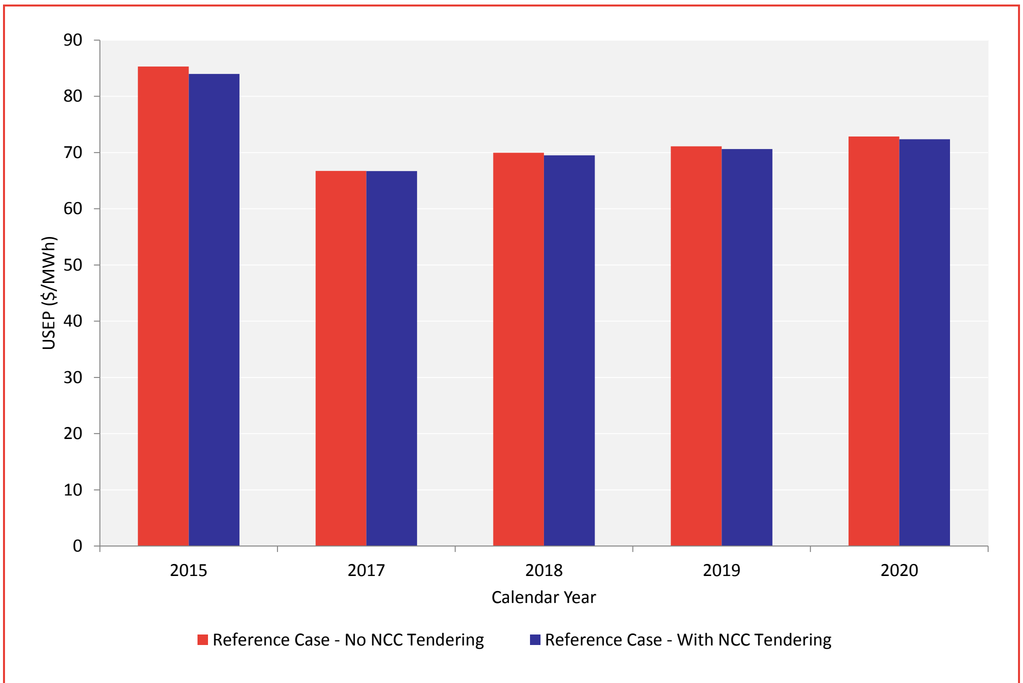
Hedge unvested MSSL load

Recalling Figure 5, we would expect that where the VCL drops below the MSSL load proportion, generators gain increasingly greater pool exposure due to reduced net contract positions and therefore have more incentive to exercise market power to increase prices in the wholesale market.

This has been shown to hold true in our analysis of setting the VCL in 2017 and 2018, where we see in Figure 18 and Figure 19 that reductions in the VCL where unvested MSSL load is unhedged result in substantial price increases, compared to the case where unvested MSSL load is prudently hedged and we even see small price reductions. Further the level of prices is higher for any given vesting level in the case where unvested MSSL load is left unhedged.

Figure 26 shows, for a vesting level of 25%, our modelling results using the average derating of forced outages approach (the approach used for the review of market power mitigation mechanisms). We can see that for this given vesting level, prices are lower where unvested MSSL load is tendered to the big 6 Gencos (in this case, on the basis of effective capacity market share).

Figure 26: Reference case – average annual USEP with and without hedging unvested NCC – VCL 25%



Source: Frontier Economics SPARK market modelling, estimates based on average outage derating approach

VC allocation – Improved vesting regime

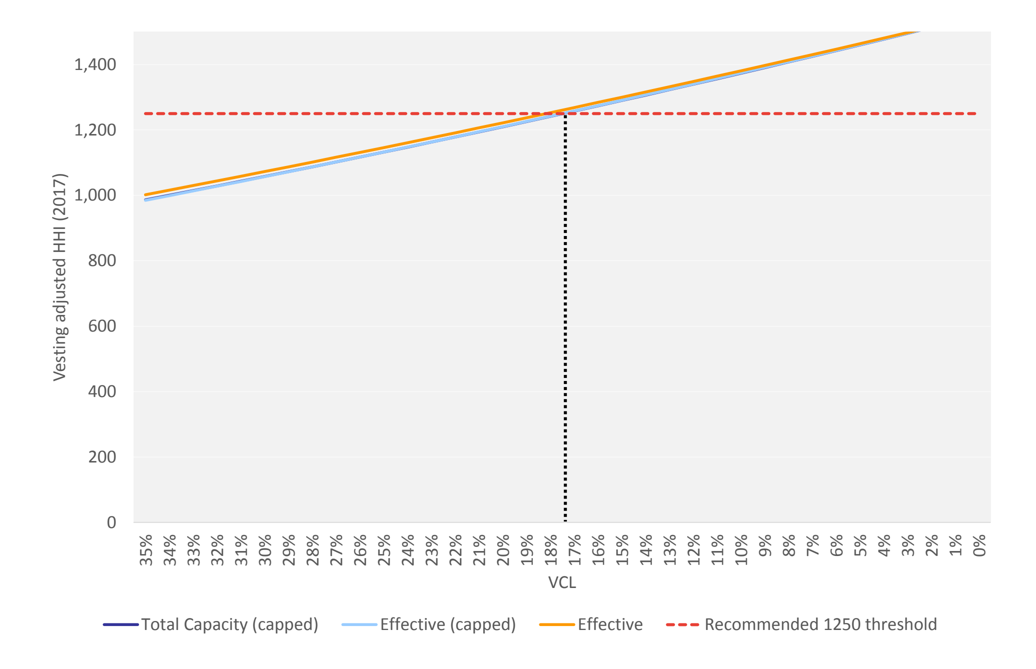
Design parameter 3 recommends setting the VCL based on a prescribed, formulaic methodology whereby the VCL would be set with a view to achieving an appropriately low 'vested HHI'. We propose that the VCL be set to achieve a vested HHI of 1,250, this being mid-way between the thresholds that the FERC and DoJ/FTC regard as needed for an unconcentrated market. Box 1 in Section 6.4.1 provides a simplified example of how this prescribed approach would be applied. In applying our approach to the actual SWEM, we have assumed that the implied VCL is calculated without accounting for the presence of the firm LNG vesting quantities. We understand this to be consistent with the EMA's procedures for calculating vesting quantities.

Figure 27 displays the findings of using the prescribed vested HHI approach to setting the VCL. This figure shows the effects of allocating vesting contracts on three different bases, and the HHI which they imply:

- Current allocation: market share of total capacity (capped at vesting start registered capacity)
- Effective capacity: market share of total CCGT + OCGT capacity (no steam)
- Effective capacity (capped): market share of total CCGT + OCGT capacity (no steam), but capped at vesting start registered capacity levels. This avoids 'over hedging' of Jurong Island Gencos

As expected, as the VCL increases (towards the left hand side of the chart) the HHI of the SWEM decreases. Conversely, allowing for a higher HHI corresponds to allowing the VCL to be reduced. To achieve the recommended HHI threshold of 1250 (see Section 6.4.1), this would roughly equate to a VCL of 17% if vesting contracts were assigned on either the current allocation method or on a capped effective capacity basis.

Figure 27: VCL Prescribed vested HHI methodology

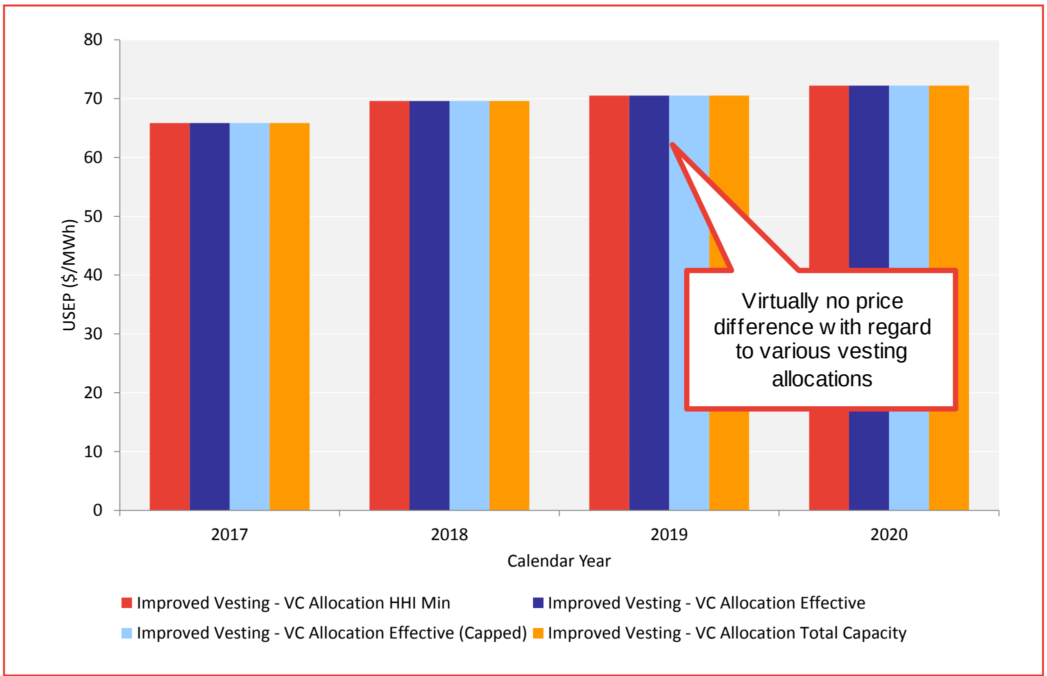


Source: Frontier Economics analysis

Figure 28 shows the market modelling results for these different vesting allocations at a VCL of 17%. Allocating vesting contracts based on effective (OCGT+CCGT) capacity, effective capped capacity or HHI minimisation[100] leads to either no change or very marginally lower forecast prices, which is consistent with the increased effectiveness we would expect according to first principals arguments. However, again, these price differences are not material.

100 HHI minimising allocation corresponds to allocating contracts to minimise the vested HHI (this effectively corresponds to the vast majority of contracts being allocated to Senoko, ~90%)

Figure 28: Improved VC package – average annual USEP – VCL 17%



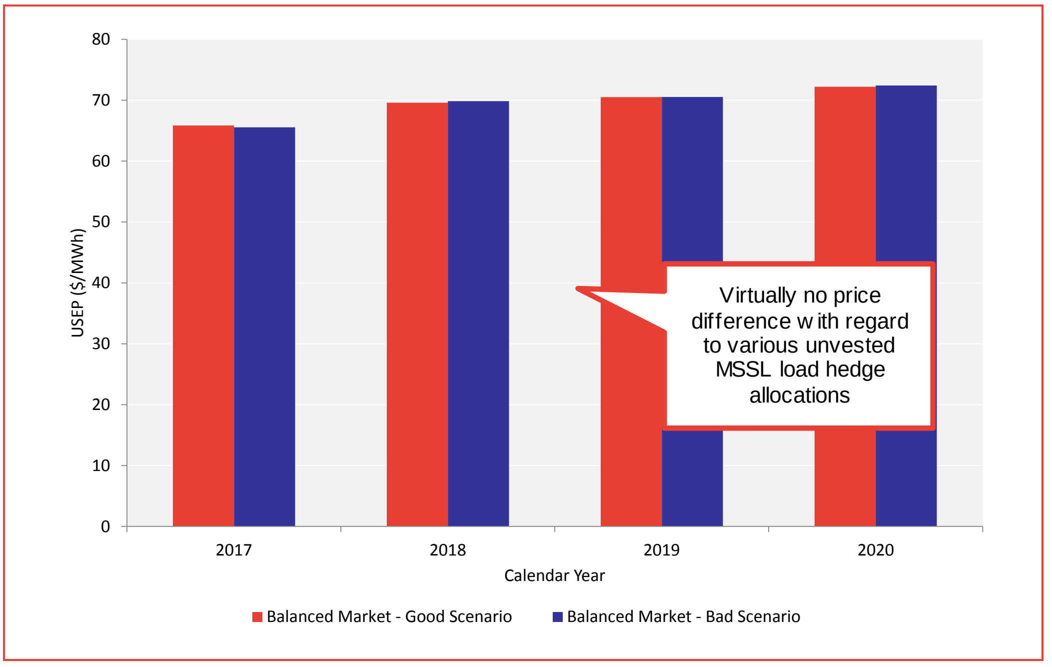
Source: Frontier Economics SPARK market modelling, estimates based on average outage derating approach

Unvested MSSL load hedge allocation

For the balanced market package, the vesting level is reduced to LNG vesting thus the allocation of vesting contracts is a non-issue. In this section we briefly investigate the implications of allocating hedges to cover unvested MSSL load to the big 6 Gencos on different bases; a 'good' scenario whereby contracts are allocated based on effective (CCGT + OCGT) capacity and a 'bad' scenario whereby contracts are allocated to maximise the HHI – keeping in mind that actual market allocation is uncertain and likely to change over time as contracts are transacted.

Figure 29 shows the results of the market modelling, which indicate that in all years apart from 2017, tendering unvested MSSL load on an effective capacity basis leads to slightly lower prices, however, the price differences are immaterial. Thus there appears to be little cause for concern regarding the extent to which a market based allocation of NCC contracts (via tender or SGX) would lead to an opportunity to exert market power.

Figure 29: Balanced market package – market modelling results

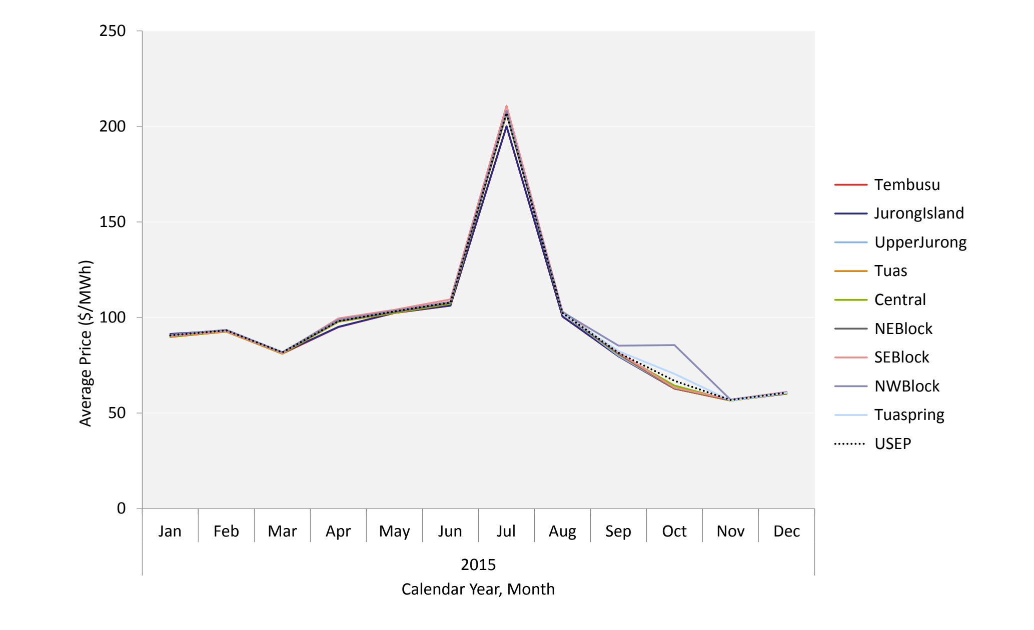


Source: Frontier Economics SPARK market modelling, estimates based on average outage derating approach

Pivotal supplier test

Figure 30 displays historic price separation magnitude for calendar year 2015. It can be seen that for the majority of times there is little price separation, however in a few instances, namely some days in July and especially October, there is evidence of substantial price separation.

Figure 30: 2015 Price Separation magnitude



Source: Frontier Economics

The details of the design and implementation of a pivotal supplier test in the SWEM are outlined in Section 6.6.1. In this section, we present the results from a stylised historical analysis of a dynamic PST.

To analyse ex-post what would have been the effects of a PST on historical price outcomes is a difficult task without extensive information regarding transmission network constraints and half hourly flow data; neither of which is currently publicly available. To overcome this, we have conducted a 'stylised' analysis based on historic nodal price information, obtained from the EMC's market data web portal. The analytical methodology is simple, yet represents what we believe to be most pertinent in light of information limitations:

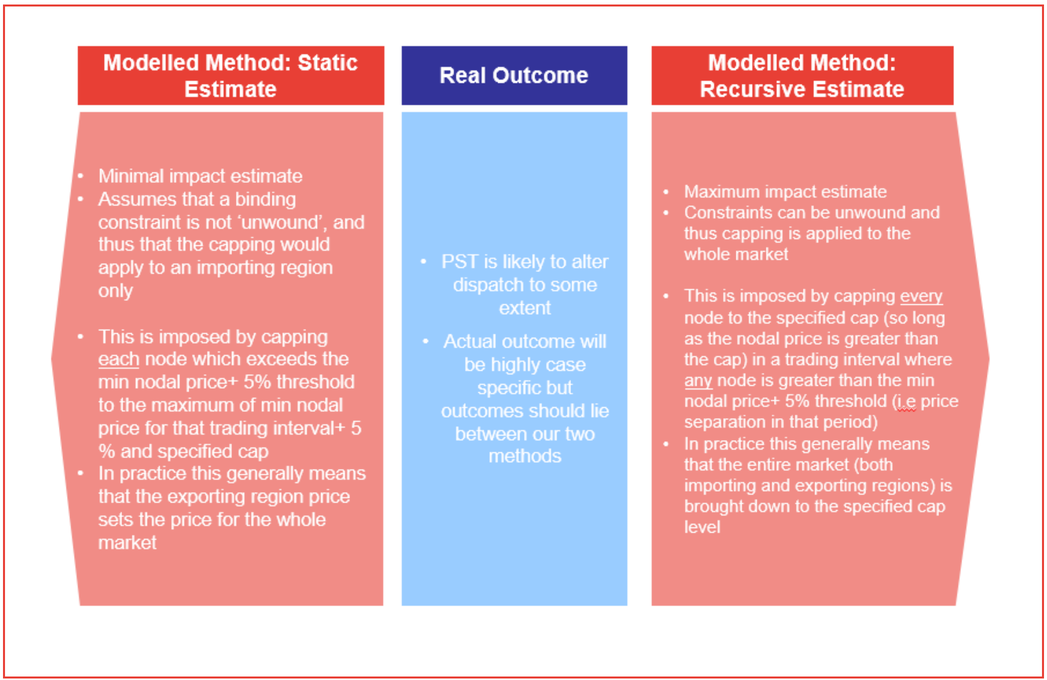
- Using historical half hourly nodal price information, we identify instances of price separation over history
  - We define price separation as periods where, for any given trading interval, any node's price exceeds the minimum nodal price by more than 5%
- Where price separation occurs, we implement 'offer capping' via one of two methods. These two methods differ in the extent to which the PST materially alters dispatch and flows, and form the 'bookends' for possible outcomes for the dynamic PST. Actual observed market outcomes from the PST would lie somewhere between these bounds:
  - A static (non-iterative) estimate which assumes that a binding constraint cannot be 'unwound' and thus that the capping would apply to an importing region only

- ▫ A recursive (proxy for iterative) method which has the underlying assumption that constraints can be unwound and thus capping is applied to the whole market

- The offers are capped at various cap levels to investigate the effects of more or less intrusive cap levels

Figure 31 outlines the analytical methodology and the specific implementation of the PST proxy in our stylised analysis.

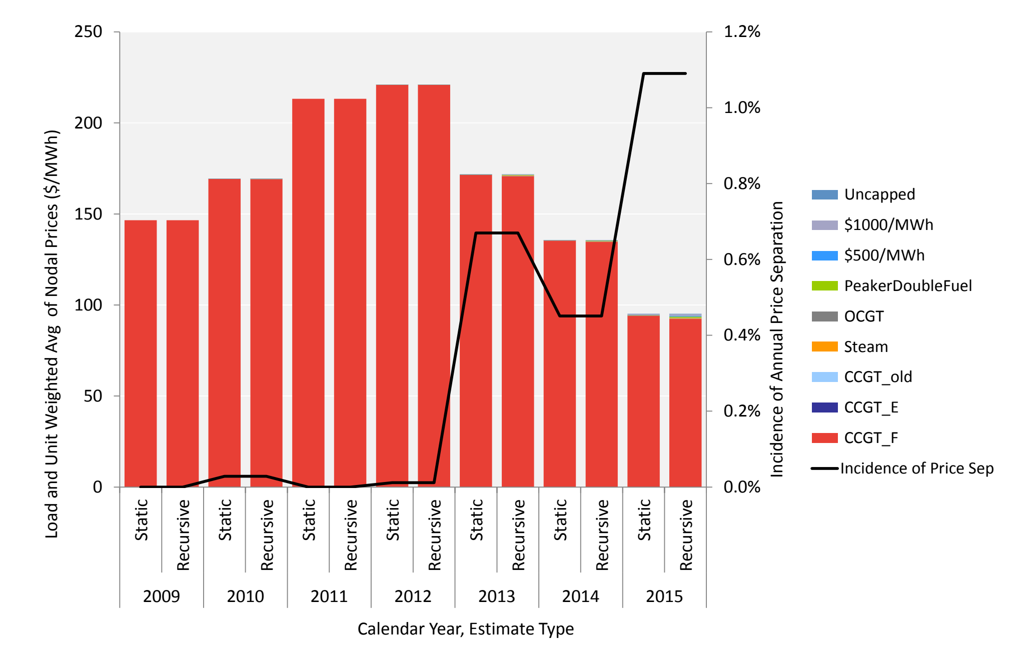
Figure 31: Dynamic PST analytical methodology



Source: Frontier Economics

Figure 32 shows the results of this analysis. Instances of price separation are low throughout history, leading to a small number of instances where the PST would apply and hence a small overall impact on average annual prices. Price separation is highest in 2015 (just over 1%) due to both July high price days and special events on days in October, leading to the greatest annual average impact being observed for this year (a mitigation of around $3/MWh for the recursive estimate, capped at the SRMC of a CCGT_F unit). The recursive estimate results in greater price mitigation compared to the static estimate, as expected, and actual outcomes would lie somewhere between these two measures.

Figure 32: Historical analysis of PST effects on USEP



Source: Frontier Economics historical analysis of EMC Nodal price data

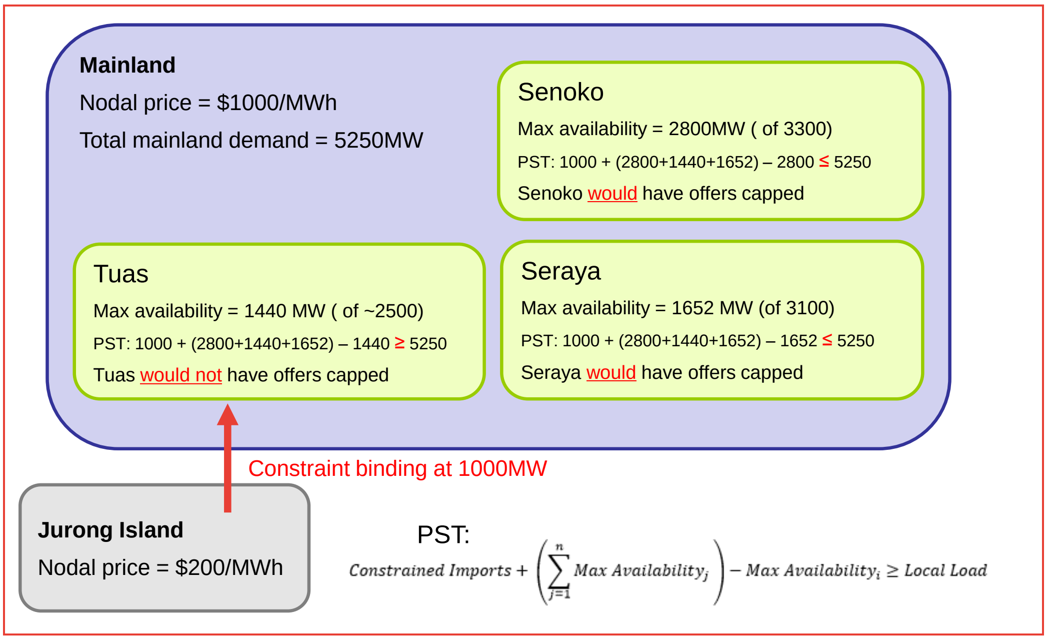
In Box 2 we provide a stylised example of how a dynamic PST would work, assuming Jurong to Mainland congestion in a given trading interval. We assume mainland local load of 5250MW (representing a high demand event) and the following maximum availabilities:

- Senoko 2800MW representing all CCGT/OCGT units (out of total registered capacity of 3300MW)
- Seraya 1652MW representing the four CCGT units and the Jurong OCGT units (out of 3100MW), and
- Tuas 1440MW representing four (out of five) CCGT units (out of ~2500MW).

That is, it is assumed that all steam units are out of the market and a single Tuas CCGT unit is unavailable. Further, imports are constrained on the interconnector between Jurong Island and the mainland at 1000MW (hypothetical line limit). In this scenario, the dynamic PST would apply to all suppliers on the mainland, since they all lie behind the constrained interconnector. Senoko fails the PST by 1158MW and therefore would have its offers capped. Similarly, Seraya fails the PST (by only by 10MW) and also has ifs offers capped. Tuas would not have their offers capped (however this partly due to assuming that Tuas has a CCGT unit out, Tuas may be deemed pivotal under other conditions). Where the local load was marginally lower, the constrained line limit was higher or a small amount more of Senoko or Seraya to be available, Seraya would not fail the PST. If 1200MW of additional plant were available, Senoko would also no longer fail the PST. Thus any supplier only fails the PST if transmission constraint occurs during times of tight demand and supply.

This example highlights that a PST would only trigger under relatively extreme events. Further, the Jurong Island to mainland constraint will be built out in the near term, so a PST is not likely to apply in such a wide-spread manner in the medium term.

Box 3: Dynamic pivotal supplier test, stylised example – constraint imports from Jurong



Source: Frontier Economics

Another stylised example is where constrained imports occur into NW Block. In this case, given that there is only a single supplier in the import constrained subregion (Senoko), the PST results in capping of the single suppliers bids. This result holds in any import constrained region with a single supplier behind the constraint.

This implies that in the medium term, where there is significant oversupply in the market, a dynamic PST is likely to more frequently correspond to capping only those suppliers at the terminal subregions. Further, it is unlikely that a PST would apply to Senoko in the NW Block unless there is significant load redistribution, as imports into the NW Block region typically exceed local load (and transmission lines into the region rarely bind). In summary, a PST is likely to apply in very few instances in the medium term given the low level of transmission congestion in the SWEM.

Market price cap

For an energy-only market design to work, wholesale market prices should be allowed to rise well above any generators' short run costs when generation supply is insufficient to meet demand. Further, to the extent that a plant can earn prices in excess of SRMC outside of load-shedding periods, the need to earn high prices during load-shedding is reduced. Section 4.6.3 discusses this and its implications in further detail.

Although it is not an element of the current vesting regime and hence is beyond the scope of our review, we hold some concerns regarding the sufficiency of the current SWEM market price cap (MPC) of S$4,500/MWh in relation to encouraging the market to provide resource adequacy in the long term. System planning in the SWEM is currently based on a minimum reserve plant margin of 30%. This is intended to cater to scheduled maintenance as well as forced plant outages and is based on a loss of load probability of three days per year.[101]

Drawing on some stylised assumptions, the implications of the SWEM reserve plant margin for the annual volume of unserved energy, peaker fixed costs and ability to earn positive operating profits outside of load shedding periods, it appears unlikely that an MPC of S$4,500/MWh would enable efficient marginal peaking plant to recover their fixed costs (see Table 12).

101 See EMA website at: https://www.ema.gov.sg/System_Planning.aspx (accessed 18 April 2016).

Table 12: Stylised MPC input parameters

Cases	1	2	3	4	5	6	7
Peaker fixed cost ($/MW)	$700,000						
Life (years)	30						
Discount rate (% real)	10%						
Operation outside load-shedding (% year)	5%	0%	1%	2%	5%	5%	5%
Average operating profit outside load-shedding ($/MWh)	$100	$0	$50	$150	$150	$100	$150
Residual ($/MW pa)	$30,455	$74,255	$69,875	$47,975	$8,555	$30,455	$8,555
Reliability standard (% annual energy unserved)	0.002%	0.002%	0.002%	0.002%	0.002%	0.01%	0.01%
Reliability standard (averaged unserved hrs pa)	0.175	0.175	0.175	0.175	0.175	0.088	0.876
Implied MPC ($/MWh)	$174K	$424K	$399K	$274K	$49K	$348K	$9.8K

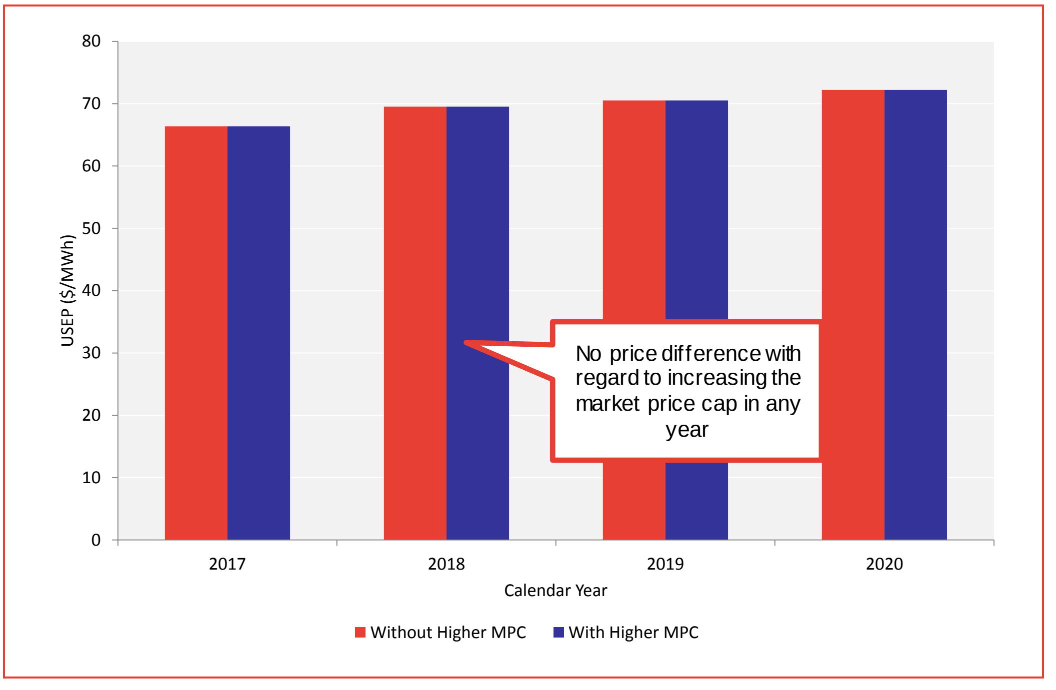
Modelling a higher MPC

Finally, we present the market modelling results of a case where we increase the price cap substantially. Figure 33 shows these results for annual average prices with the current market price cap of $4,500/MWh imposed and a case where the market price cap is raised to $400,000/MWh[102]. We observe no price difference or unserved energy with regard to increasing the market price cap to $400,000/MWh, using the assumed average derating approach for generator forced outages.

102 Note that we would not propose increasing the market price cap to $400,000/MWh, we simply use this figure as a sensitivity for an extreme case.

This results implies that even if MPC were significantly higher, there would be no Nash equilibria where generators bid to raise prices to the price cap during market conditions consistent with average levels of generation forced outages. This suggests that there would be limited ability for a higher market price cap to lead to greater exercise of market power however further analysis of incentives under extreme market conditions is recommended (as per Recommendation 2).

Figure 33: Combined package – market modelling results – LNG vesting



Source: Frontier Economics SPARK market modelling, estimates based on average outage derating approach

FRONTIER ECONOMICS
MELBOURNE | SYDNEY | BRISBANE | SINGAPORE
Frontier Economics Pty Ltd 395 Collins Street Melbourne Victoria 3000
Tel: +61 (0)3 9620 4488 Fax: +61 (0)3 9620 4499 www.frontier-economics.com.au
ACN: 087 553 124 ABN: 13 087 553 124h