TEMPORARY PRICE CAP MECHANISM

FINAL DETERMINATION PAPER

16 June 2023

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Background

1 In the changing energy landscape, new sources of supply risks and volatility have emerged:

a. **Risks of gas supply disruptions and price shocks**. The global energy market has become more volatile amidst geopolitical tensions and the global energy transition. This is particularly salient for Singapore as we rely on imported natural gas for almost all our electricity production. As fuel prices surged in 4Q 2021, the domestic electricity market was severely tested – generation companies ("**Gencos**") were reluctant to contract for term gas, for fear that they would be left holding on to expensive gas should prices moderate subsequently. This in turn increased the risks of gas shortfalls and contributed to wholesale electricity price volatility.

b. **Risk of insufficient generation capacity**. Today, investments in new generation capacity are driven by each Genco's commercial considerations. This can lead to prolonged periods of over- and under-supply (since it takes ~four to five years to plant a new generation unit) and in turn lead to highly volatile electricity prices. These cyclical mismatches in supply and demand could worsen with the global climate imperative, as rising carbon taxes and the energy transition could discourage investments in thermal generation units which will still be needed to meet electricity demand in the near and medium-term.

c. **Risks of market failure**. As observed in the global energy crisis, Gencos' risk aversion inhibited the self-equilibrating mechanisms in the power market which led to a vicious cycle of more volatile conditions and extreme electricity price movements. This led to six electricity retailers exiting the market in 4Q 2021 as they were not sufficiently prepared to deal with the extreme market volatilities. While affected consumers did not experience any disruption to their power supply, some of them experienced inconvenience and a sharp rise in electricity cost when sourcing for alternative electricity retail contracts.

2 Governments around the world are reviewing their approach towards energy markets to ensure energy security and stability. In Oct 2022, the Ministry of Trade and Industry ("**MTI**") announced that the Energy Market Authority ("**EMA**") will be introducing guardrails to strengthen the existing competitive market structure and ensure that Singapore is well-positioned to navigate the energy transition.

3 One of the guardrails is a **Temporary Price Cap** (“**TPC**”) mechanism to mitigate extreme price volatility in Singapore Wholesale Electricity Market (“**SWEM**”).

Need for Guardrail to Mitigate Wholesale Electricity Price Volatility

4 The SWEM determines the least-cost dispatch of offers to supply energy, reserves and regulation for every half-hour trading period (“**TP**”), based on competitive supply offers from Market Participants (“**MPs**”) such as the Gencos. The offer needed to meet marginal demand will set the market-clearing price, referred to as the Uniform Singapore Energy Price (“**USEP**”), and offers below the market-clearing price would be dispatched.

5 There is an existing Energy Price Cap of <u>$4,500/MWh</u> in the SWEM. The $4,500/MWh price cap is determined based on the Value of Loss Load (“**VoLL**”) which reflects the economic cost of an energy supply shortfall. The USEP may reach the Energy Price Cap during a system stress event, which should incentivise the supply-side (e.g. Gencos) to increase supply, and the demand-side to reduce demand. However, prolonged periods of extreme USEP volatility as observed during the global energy crisis led to Gencos reducing supply instead. Gencos became risk averse and reduced supply to preserve spare generation capacity to serve their contractual demand should their generation units experience unanticipated outages or gas supply disruptions. This further drove up USEP and resulted in a vicious cycle of volatility and risk aversion.

6 Extreme SWEM volatility also made the Gencos hesitant to enter into retail contracts, as they would need to buy from the SWEM at volatile prices should they experience unanticipated outages or gas supply disruptions. Consumers faced difficulties securing electricity contracts, especially those who used to buy directly from the SWEM. In addition, Independent Retailers (“**IRs**”) were especially affected by the extreme price volatility in the SWEM. Since 4Q 2021, six IRs have exited the market as they were no longer able to sustain their operations.

7 In view of the above, a TPC mechanism is needed to act as a “circuit breaker” to mitigate vicious cycle of sustained volatility and risk aversion in the SWEM and restore the orderly functioning of the broader market. Similar mechanisms have been implemented in other jurisdictions with an energy-only market, such as Australia, the Philippines and Texas. Refer to ***Appendix 1*** for more details.

8 EMA has conducted a public consultation (from 17 Jan to 14 Feb 2023) and further engaged the industry stakeholders to develop the TPC design and initial parameters to be effected on and from 1 July 2023. Taking into account the characteristics of our domestic energy sector and feedback from the consultations, EMA’s final determination is set out below.

Overall Intent and Design Framework for the TPC Mechanism

9 The TPC mechanism is intended to act as a short-term measure to stop the vicious cycle of volatility and risk aversion, and allow time to identify and address the cause(s) of the extreme price volatility, by temporarily capping the USEP at a level lower than the existing Energy Price Cap. When activated in times of extreme price volatility, it will mitigate excessive risks to all SWEM participants including Gencos, retailers and consumers buying from the SWEM, while still allowing the USEP to fluctuate and reflect demand and supply conditions.

10 The TPC will be activated in response to a combination of two key parameters, viz. (a) the average USEP over a specified number of consecutive half-hour TPs referred to as the Moving Average Price ("**MAP**"); and (b) a specified threshold referred to as the Moving Average Price Threshold ("**MAPT**"). Specifically, the TPC will be imposed for the next and subsequent TPs in the SWEM when the MAP (based on the USEP in the current and preceding TPs) exceeds the MAPT.

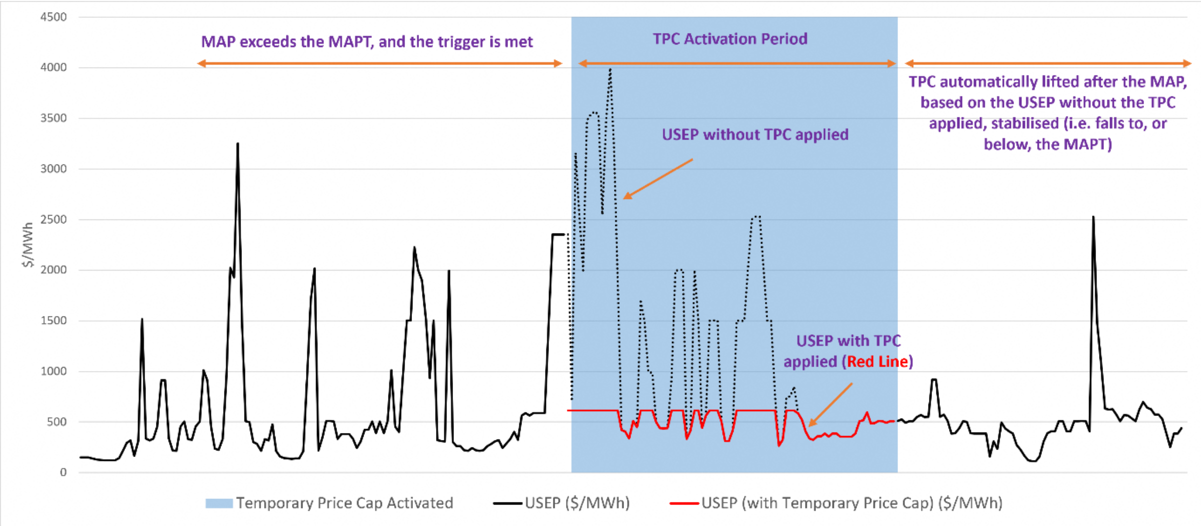
11 For a given TP ('*T*') when the TPC is in place:

a. All energy suppliers such as the Gencos will <u>continue to submit energy offer prices up to the Energy Price Cap of $4,500/MWh</u>.

b. If the marginal energy offer price (i.e. the highest energy offer price needed to meet system demand) is <u>below</u> the TPC, the USEP will continue to be set based on the marginal energy offer price. If the marginal energy offer price is <u>at or above</u> the TPC, the USEP will be <u>capped at the TPC</u>.

12 The TPC will be automatically lifted from the <u>next TP (i.e. '*T+1*')</u> if the MAP up to and including the TP '*T*' based on the <u>counterfactual USEP</u> (i.e. the marginal energy offer price up to the $4,500/MWh Energy Price Cap) has normalised at or below the MAPT ("**Off-Trigger**"), subject to keeping the TPC in place for a specified minimum number of TPs after being triggered ("**Minimum Trigger Period**" or "**MTP**"). See ***Figure 1*** below for an illustration.

Figure 1: Illustration of the TPC Mechanism



EMA's Proposed TPC Parameters in the Consultation Paper

<u>Level of the TPC</u>

13 The TPC level should be set appropriately to allow the recovery of long-run marginal cost ("**LRMC**") for the majority of the generation capacity in the system, while allowing the USEP to fluctuate and reflect the prevailing demand and supply conditions, and at a suitable level to mitigate the vicious cycle of sustained price volatility and risk aversion.

14 EMA proposed in the consultation to set the TPC at <u>the LRMC of combined cycle gas turbine ("**CCGT**") generation units</u> ("**CCGT LRMC**") multiplied by <u>1.5 times</u> ("**1.5x**"). More specifically, the CCGT LRMC will be set based on the prevailing vesting price parameters, which are benchmarked to the most efficient CCGT technology that accounts for at least 25% of the system demand in Singapore. To account for the prevailing marginal cost of fuel, EMA will on a bi-weekly basis, update the fuel cost component of the CCGT LRMC using the higher of either: (a) spot gas prices based on the Japan-Korea Marker or "**JKM**" ("**Spot LRMC**"), or (b) the term gas prices under specified Gas Supply Agreements ("**GSAs**") for power generation ("**Term LRMC**").

15 Should an energy supplier in the SWEM be dispatched to supply energy, in a trading period when the USEP was capped during a TPC activation but was unable to recover its actual costs of supply, it may seek compensation under the Singapore Electricity Market Rules ("**Market Rules**").

<u>On-Trigger</u>

16 The TPC will be triggered/activated when there is extreme USEP volatility as reflected by the combination of two key parameters, viz. the MAP and MAPT, working

collectively. A shorter period for averaging the USEP to compute the MAP, and/or a lower MAPT, will increase the likelihood of activating the TPC, *ceteris paribus*.

17 To calibrate the MAP and MAPT, EMA examined the USEP from Jan 2021 to Sep 2022 ("**Period 1**"), covering the market situation before and during the global energy crisis, to establish a standard deviation benchmark of between $183/MWh and $1,349/MWh ("**SD Benchmark**") where risk aversion behaviour was observed.[1] This was significantly higher than the average USEP SD of $34/MWh in 1H 2021 pre-crisis. Further market simulations were conducted together with the Energy Market Company ("**EMC**") to study the effect of various combinations of MAP and MAPT. A MAP of 48 TPs and MAPT at two times ("**2x**") CCGT LRMC was recommended as it was observed (based on back-casting using historical data) to avoid TPC activation pre-crisis where volatility was below the SD Benchmark (with a lower MAPT) while being able to capture those periods when the SD Benchmark was met during the crisis. Refer to the ***consultation paper*** for more details on the calibration of the MAP and MAPT.

Off-Trigger

18 After the TPC is activated, it will be automatically deactivated for the next TP '*T+1*' if the MAP up to and including the current TP '*T*' based on the counterfactual USEP (i.e. the marginal energy offer price up to the $4,500/MWh Energy Price Cap) has normalised at or below the MAPT. To provide adequate time for the market to stabilise and prevent the Energy Price Cap from oscillating between the TPC and $4,500/MWh intra-day, EMA proposed that the TPC once activated should be in place for a Minimum Trigger Period ("**MTP**") of 48 consecutive TPs including the first TP of activation.

19 EMA's proposed parameters in the consultation paper are summarised in ***Table 1*** ("**Original Proposal**").

Table 1: EMA's Proposed TPC Parameters in the Consultation Paper

TPC	MAPT	MAP Period	MTP
1.5x CCGT LRMC	2x CCGT LRMC	48 TPs (i.e. 1 day)	48 TPs

Adjustments to the Price Caps for Reserves and Regulation

20 When the TPC is triggered, the price caps for reserves (i.e. primary and contingency) and regulation services should be correspondingly adjusted proportionately. This is to ensure that the relative price signals in the energy, reserves and regulation markets are preserved, to mitigate perverse incentives and unintended

[1] Specifically, the months of Jul 2021, Nov-Dec 2021, Jan-May 2022, and July-Aug 2022 were observed to have projected supply shortfall above the median level in Jan 2021 to Sep 2022, based on the Day-Ahead Run ("**DAR**") published by the EMC.

consequences where a Genco offers more to provide reserve rather than energy, which will aggravate the ongoing system stress situation. The TPC when activated will not be applied to the Demand Response Scheme to encourage demand response providers to continue to offer their services to reduce demand and help to normalise the market and facilitate deactivation of the TPC. The proposed adjustments are shown in ***Table 2*** below.

Table 2: Adjustments to Price Caps for Energy, Reserves and Regulation during TPC Activation

Item	Adjusted Price Caps
Nodal Price	Capped at TPC
USEP	Capped at TPC
Primary and Contingency Reserve prices	Capped at the ratio between the prevailing TPC and Energy Price Cap of $4,500/MWh.
Regulation price	Capped at the ratio between the prevailing TPC and Energy Price Cap of $4,500/MWh.

21 In summary, the proposed TPC parameters are set based on back-casting using historical data. There may be future periods of sustained and extreme volatility observed in the SWEM which may not be sufficiently addressed with the prevailing TPC parameters. To enable EMA to mitigate extreme price volatility and restore the orderly functioning of the market in a timely manner, EMA may conduct consultations on modifications to the TPC mechanisms and effect the modifications, in an expedited manner.

EMA's Assessment of Industry Feedback

22 At the close of the consultation, nine market participants ("**MPs**") provided feedback including six Gencos and three Embedded Generators ("**EGs**"). Detailed feedback and EMA's responses are provided under ***Annex 1 – TPC Consultation Feedback and Responses***.

23 There were no objections to the objective and benefits of the proposed TPC mechanism. The respondents concurred with the adverse spill-over impact of sustained USEP volatility on the broader electricity market. However, the Gencos proposed for a higher floor to the CCGT LRMC on account that spot gas prices can potentially be low relative to term gas prices in times of normal global energy market conditions. Specifically, the Genocs suggested for (i) the MAPT and TPC parameters to be set at **Max [3x Term LRMC, 2x Spot LRMC]**; (ii) a higher MAP of 3-7 days; and (iii) a shorter MTP of 24 TPs (i.e. 0.5 days). ***Table 3*** summarises the Gencos' proposed parameters.

Table 3: Gencos' Proposed TPC Parameters

TPC	MAPT	MAP Period	MTP
Max [3x Term LRMC; 2x Spot LRMC]		3-7 days	24 TPs

24 EMA/EMC conducted additional simulations to study the effect of the Gencos' proposal, with an extension of the simulation period to include Oct 2022 to Apr 2023 ("**Period 2**") which captures the normalisation of spot gas prices in recent months. The detailed simulation scenarios and results are set out in ***Appendix 2***.

TPC Level and MAPT

25 The CCGT LRMC, which is used to set the TPC and MAPT parameters, is based on the higher of the Term and Spot LRMC to account for the prevailing marginal cost of fuel. For ***Period 1***, the Gencos' Proposal did not have material impact on market outcomes (as compared to EMA's Original Proposal) because during the global energy crisis, JKM was higher than term gas prices and therefore the higher Spot LRMC sets the CCGT LRMC. For ***Period 2***, the Gencos' Proposal did not capture an activation on 20 Feb 2023 although an USEP SD of $589/MWh was recorded on the back of a transmission outage, which was within the SD benchmark and similar to the USEP SD of $572/MWh recorded in Nov 2021 at the onset of the energy crisis.

26 Nonetheless, EMA agrees that the MAPT and TPC levels should be calibrated in a timely manner that accounts for normal as well as high and volatile spot gas prices. Accordingly, EMA will adopt a 'dynamic' multiplier ("**Multiplier**") on the CCGT LRMC to set the MAPT and TPC. The Multiplier will be automatically and systematically reduced in tandem with increasing difference between the prevailing JKM and term gas prices ("**Gas Spread**").

27 To calibrate the Multiplier, EMA examined the distribution of the daily Gas Spreads[2] from Jan 2021 to Apr 2023, which captures the fluctuations in fuel prices before, during and after the energy crunch. In this period, the lowest and highest daily Gas Spreads observed was -S$2.99/mmbtu and S$98.87/mmbtu respectively. The Gas Spreads were divided into 4 Quartiles[3] (from the lowest historical Gas Spread in the 1st Quartile, to the highest historical Gas Spread in the 4th Quartile). A Multiplier of between 1.5x to 3x is assigned (in equal steps of 0.5x) to each Quartile. Accordingly, the Multiplier will be set at 1.5x should daily JKM reaches extreme levels in the 4th Quartile range, with a Gas Spread of up to ~US$85/mmbtu or S$98.87/mmbtu (as observed during the energy crisis) or higher, i.e. the TPC and MAPT will be set at 1.5x CCGT LRMC. On the other hand, should JKM be lower such that the Gas Spread falls

[2] The differences between the prevailing JKM and term gas prices. For simulation purposes, the latter is assumed to be at the vested gas price.

[3] Across Jan 2021 - Apr 2023, the 1st/2nd/3rd/4th quartile of the Gas Spreads were determined to be 2.31/14.39/29.54/98.87 (in S$/mmbtu).

within the 1st Quartile range, then both the TPC and MAPT will be set at 3x CCGT LRMC. Refer to ***Table 4*** for the specific Multiplier to be used which will be updated based on the bi-weekly Gas Spread between the JKM and term gas prices to be used for determining the Spot LRMC and Term LRMC respectively for the purpose of the TPC.

Table 4: Gas Spread and Corresponding MAPT/TPC Multiplier

Multiplier	**Gas Spread (S$/mmbtu)**
1st Quartile: **3x**	Gas Spread ≤ 2.31
2nd Quartile: **2.5x**	2.31 < Gas Spread ≤ 14.39
3rd Quartile: **2x**	14.39 < Gas Spread ≤ 29.54
4th Quartile: **1.5x**	29.54 < Gas Spread

28 In summary, with the Multiplier as shown in ***Table 4***, the MAPT and TPC levels will be set at 3x CCGT LRMC, when the Gas Spread is low or negative (i.e. in the 1st Quartile range), which is similar to the Gencos' Proposal of Max [3x Term LRMC, 2x Spot LRMC] to specifically cater for normal gas prices.

29 EMA performed further simulations across Periods 1 and 2 (covering Jan 2021 to Apr 2023) to assess the frequency of TPC activations and corresponding impact on USEP using the Multiplier as shown in ***Table 4***. Refer to ***Appendix 2*** for the detailed simulation results. Relative to the 'static' Multiplier proposed by the Gencos, the 'dynamic' Multiplier would capture 3 more brief activations[4] in the months of Dec 2021, Jan and Apr 2022 where a Gas Spread of between S$34.74/mmbtu and S$36.33/mmbtu was recorded, with the MAPT/TPC multiplier set at 1.5x. The USEP SD of these activations was between S$343/MWh and S$761/MWh which was within the USEP SD benchmark of S$183/MWh and S$1,349/MWh observed during the energy crisis. Overall, the impact on USEP was marginally higher at 7.3% reduction (average USEP of $231.31/MWh) under the Multiplier approach, as compared to 5.7% reduction (average USEP of $233.85/MWh) based on the Gencos' Proposal across Jan 2021 to Apr 2023.

30 **On balance, EMA will adopt the Multiplier approach with the parameters as shown in *Table 5* which provide clarity and transparency to the market on how the MAPT/TPC levels would be systematically adjusted in a timely manner taking into account volatility in spot gas prices.**

[4] Refers to additional activation periods of 16-18 Dec 2021, 9-11 Jan 2022 and 4-6 Apr 2022 captured under the Multiplier approach (i.e. Scenario G) as compared to the Gencos' Proposal under Scenario B. Refer to Appendix 2 for more details.

Table 5: EMA's Final Determination for TPC/MAPT Parameters

TPC	MAPT
Multiplier x CCGT LRMC; Multiplier to be set in accordance with ***Table 4***	

MAP

31 The Gencos proposed to adopt a MAP of 3-7 days, to align with the Philippines/Australia markets, and the typical duration for the Power System Operator ("**PSO**") to review and allow generation units that went on forced outage to run up.

32 EMA will maintain the MAP at 48 TPs. There is no basis to align the MAP with other jurisdictions or to the typical duration for a generation unit on forced outage to return to service. For instance, the Australia TPC has a MAP of 7 days, designed to mitigate wholesale electricity price volatility arising from extreme weather events (e.g. droughts, heatwaves), which is different from the objective of the TPC in Singapore. For the Singapore market, allowing the USEP to remain volatile for 3-7 days before activating the TPC which would result in adverse impact to the SWEM as observed in 2H 2021. This is corroborated by the simulation results which show that the TPC mechanism with a MAP of 3-7 days would not respond effectively to extreme USEP volatility. In particular, the TPC with MAP of 3-7 days would not be triggered for the period 26-27 Nov 2021 (where the USEP SD was >$1000/MWh on the back of PNG curtailment and forced outage of a baseload generating unit) as well as for the episodes in 1Q 2022 through 1Q 2023 (where USEP SD averaged $717/MWh which is around the average volatility in months with significant projected supply shortfalls in the SWEM).

MTP

33 Some Gencos proposed to set the MTP at 24 TPs (i.e. 0.5 day) on the basis that it would adequately cover peak hours where elevated prices would more likely occur as well as provide ample time for the market to readjust and stabilise.

34 System stress events may happen at any time of the day. As such, a MTP of only 24 TPs or 0.5 day can potentially off-trigger and trigger again the TPC within the same day. EMA will therefore retain the MTP at 48 TPs to provide reasonable time for the market to stabilise and prevent the Energy Price Cap from oscillating between the TPC and $4,500/MWh intra-day.

Reserves and Regulation Price Cap

35 Some MPs commented that the reserves price cap should not be adjusted on the basis that sustained USEP volatility could be due to supply constraints which could be eased by reserves, and lowering the reserves cap would dis-incentivise supply of reserves. They further commented that the Australian mechanism should be adopted where the reserve price is capped at the TPC price as it reflects the opportunity cost of providing energy.

36 EMA has assessed that when the TPC is in place, corresponding adjustments to the reserves and regulation price caps are essential to maintain relativity in prices, and in turn convey the correct market price signals for prioritising the supply of different products/services required in the power system. Should the Primary and Contingency Reserve Price Caps ($4,250/MWh and $3,250/MWh respectively) not be correspondingly adjusted when TPC is activated, this could lead to undesirable changes in MPs' bidding behaviour (e.g. bidding more into the reserves rather than energy) which will aggravate the system stress situation. EMA will therefore retain the adjustment to the reserves price cap.

Demand Response ("**DR**")

37 Some Gencos suggested that should DR providers be exempted from the TPC, the same treatment should be applied to open-cycle gas turbines ("**OCGTs**") on the basis that they play a similar role to rebalance and normalise the market with a short response time. They further commented that from a level playing field perspective, if the DR is exempted, all generating units should be exempted.

38 EMA has assessed that extreme price volatility typically arise on the supply-side factors due to higher and/or inadequate offers from the Gencos. The exclusion of demand-side resources such as DR providers would incentivise more demand-side participation and in turn help to normalise the market and deactivate the TPC faster. **EMA will therefore only exempt DR from the TPC.**

Directed Supply Scheme ("**DSS**")

39 Some Gencos feedback that the DSS should be ceased should the TPC be implemented citing that (a) having both schemes concurrently may be excessive and undermine the competitive nature of SWEM, and (b) excessive intervention will distort market signals and decrease incentives for Gencos to invest in new capacity.

40 EMA would clarify that the DSS and TPC mechanism serve different purposes. The DSS, is intended to guard against projected supply shortfall in the SWEM to ensure power system reliability while the TPC is intended to mitigate vicious cycles of extreme price volatility to restore orderly functioning of the market.

Waiver of 5-year Notice Period for Plant Retirement

41 Some Gencos feedback that the TPC would reduce the economic lifespan of OCGTs and older spare generation units. They suggested to be given a 6-month period to reassess the remaining economic lifespan of such generation units after the TPC is implemented and during this period, be allowed to provide less than 5 years' notice to retire those units.

42 EMA would clarify that the 5-year notice period for plant retirement is intended to facilitate orderly entry and exit of generation capacity. With the introduction of the TPC, older and less efficient generation units may seek compensation should they not be able to recover actual cost of supply when dispatched during TPC activations.

Compensation Framework

43 Some MPs asked for details of the compensation framework under the TPC. EMA would clarify that the compensation framework is independent of the TPC mechanism and should be aligned with that for the DSS. As such, EMA will separately develop a fair and reasonable compensation framework that covers actual cost of supply including reasonable margins. EMA will consult industry on the compensation framework in due course.

Data Transparency

44 Some MPs requested for data and methodology transparency in relation to the TPC mechanism, including the methodology to determine the Spot LRMC. The methodology to determine the Term LRMC and Spot LRMC is provided in ***Appendix 3***. EMA will separately work with EMC to publish the information as indicated in ***Table 6.***

Table 6: Publication of Data for TPC

Frequency	**Data**
For each TP	RUSEP (i.e. uncapped counterfactual USEP during a TPC activation), MAP, MAPT, TPC Status
Bi-weekly or as determined by EMA (to be published 5 business day ("**5BD**") before effective date)	Term LRMC, Spot LRMC, TPC, TPC Reserves Cap, TPC Regulation Cap, Multiplier

Market Rules

45 EMC/EMA conducted a consultation (from 21 Feb to 7 Mar 2023) on the Market Rules modifications required to implement the TPC mechanism. One feedback was that in the event of the Market Clearing Engine ("**MCE**") failing to produce a Real-Time Schedule ("**RTS**") for a TP, the latest Short-Term Schedule ("**STS**") Medium demand scenario should be used to calculate the MAPT/MAP for the purpose of activating/deactivating the TPC, instead of omitting such TP which reduces the number of dispatch periods in the calculations. EMA is of the view that using the projected USEP for such TP in the STS to activate/deactivate the TPC may prematurely activate/deactivate the TPC. Further analysis is required to determine the appropriateness of using the STS for such TP for the purpose of the TPC mechanism. In the meantime, it is reasonable to omit such TP for the purpose of the TPC mechanism, especially given that it is a rare occurrence, constituting only 0.05% of all TPs since the inception of the SWEM in 2003.[5]

46 The other key feedback was for the TPC parameters to be clearly defined in the Market Rules including the timeline for notice of changes to the parameters. The TPC parameters will be appropriately defined or referenced in the Market Rules. For transparency, the key relevant information needed to determine the parameters will be published before effecting any changes including updates to the parameter values.

47 The finalised Market Rule modifications required to effect TPC mechanism as set out in this Final Determination Paper are set out in ***Appendix 4***.

Timelines and Next Steps

48 The TPC design as set out herein (including the parameters as summarised in ***Table 7***) will be effected <u>on and from 1 Jul 2023</u>. To ensure the TPC parameters remain fit for purpose, EMA intends to review the TPC parameters in consultation with industry by 3Q 2025, after collecting 2 years of operational data.

Table 7: TPC Parameters

TPC	MAPT	MAP Period	MTP
Multiplier x CCGT LRMC; Multiplier to be set in accordance with ***Table 4***		48 TPs (i.e. 1 day)	48 TPs

* * *

[5] The proportion of TPs without RTS in the more recent 10 years, i.e. 1 Jan 2013 to 31 May 2023, is 0.02%.

Appendix 1 – Jurisdiction Scan

	Australia National Electricity Market ("NEM")	**Philippines** Wholesale Electricity Spot Market ("WESM")	**Texas** Electric Reliability Council of Texas ("ERCOT")
Description	Australia's NEM has a default market price cap and a cumulative price threshold mechanism that caps prices at the lower administered price cap if prices over seven days breach said threshold.	The Philippines' WESM has a default primary offer cap that limits offer prices and a secondary price cap that limits the resulting market prices when the rolling average price over 3 days breaches the cumulative price threshold.	Texas' ERCOT operates the Scarcity Pricing Mechanism ("SPM"). The SPM is a two-tiered price mitigation measure; the high system-wide offer cap is a year-long default cap, and the lower system-wide offer cap is activated when prices breach a threshold.
Current Parameters			
Price Cap[6]	Market Price Cap: 15,500 AUD/MWh (~13,950 SGD/MWh) Administered Price Cap: 600 AUD/MWh (~540 SGD/MWh)	Primary Offer Cap PhP32,000/MWh (~768 SGD/MWh) Secondary Price Cap: PhP6,245/MWh (~150 SGD/MWh)	High system-wide offer cap: 5,000USD/MWh (~7,000 SGD/MWh) Low system-wide offer cap: 2,000USD/MWh (~2,800 SGD/MWh)
Trigger for Secondary Price/Offer Cap	The administered price cap will be triggered once spot prices breach 1,398,100 AUD or 693.50 AUD/MWh over the previous 7 days.	The secondary price cap will be triggered once they breach a PhP9,000/MWh rolling average price over a 3-day period.	The system-wide offer cap will be set equal to the HCAP at the beginning of each calendar year and maintained at this level until the peaker net margin[7] exceeds a

[6] The currency conversion are based on 1 AUD = 0.90 SGD, 1 PhP = 0.024 SGD, 1 USD = 1.4 SGD.
[7] Peaker Net Margin is defined here as the amount of net revenue a hypothetical peaking unit might have earned in a year, given real-time power prices and spot gas prices.

			threshold of three times the cost of new entry of new generation plants.
Links	• Operation of Administered Price Cap • 2022-2023 Market Price Cap and Cumulative Price Threshold • Evolution of the Market Price Cap • Recent Urgent Rule Change to Revise the Administered Price Cap, dated 17 November 2022	• Latest mention of current WESM Price Cap (footnote in pg 28 of report)[8] • Philippines' Energy Regulatory Commission's Resolution No 20, Series of 2014 on the Secondary Price Cap as a Price Mitigation Measure • Decision to reduce rolling average to 3 days from 5 days in 2021	• ERCOT Rules Regarding its Scarcity Pricing Mechanism • Consultation and Considerations on the Caps used in the SPM by the Public Utility Commission of Texas

[8] The current Primary Offer Cap level is determined in the WESM Tripartite Resolution Joint Resolution No.3, series of 2015.

Appendix 2 – Simulation Results on Gencos' Proposals

Table A2-1: TPC Parameters for Scenarios A-F

Scenario	TPC	MAPT	MAP Period	MTP
A (EMA's Original Proposal)	1.5x CCGT LRMC	2x CCGT LRMC	48 TPs	48 TPs
B (Gencos' Proposal)	Max [3x Term LRMC, 2x Spot LRMC]		48 TPs	48 TPs
C	1.5x CCGT LRMC	2x CCGT LRMC	48 TPs	24 TPs
D	1.5x CCGT LRMC	2x CCGT LRMC	144 TPs (i.e. 3 days)	48 TPs
E	1.5x CCGT LRMC	2x CCGT LRMC	240 TPs (i.e. 5 days)	48 TPs
F	1.5x CCGT LRMC	2x CCGT LRMC	336 TPs (i.e. 7 days)	48 TPs
G (Multiplier)	Multiplier x CCGT LRMC; Multiplier to be set in accordance with ***Table 4***		48 TPs	48 TPs

Figure A2: No. of Activations and Monthly Average USEP SD across Simulation Periods 1 & 2 for Scenarios A – G

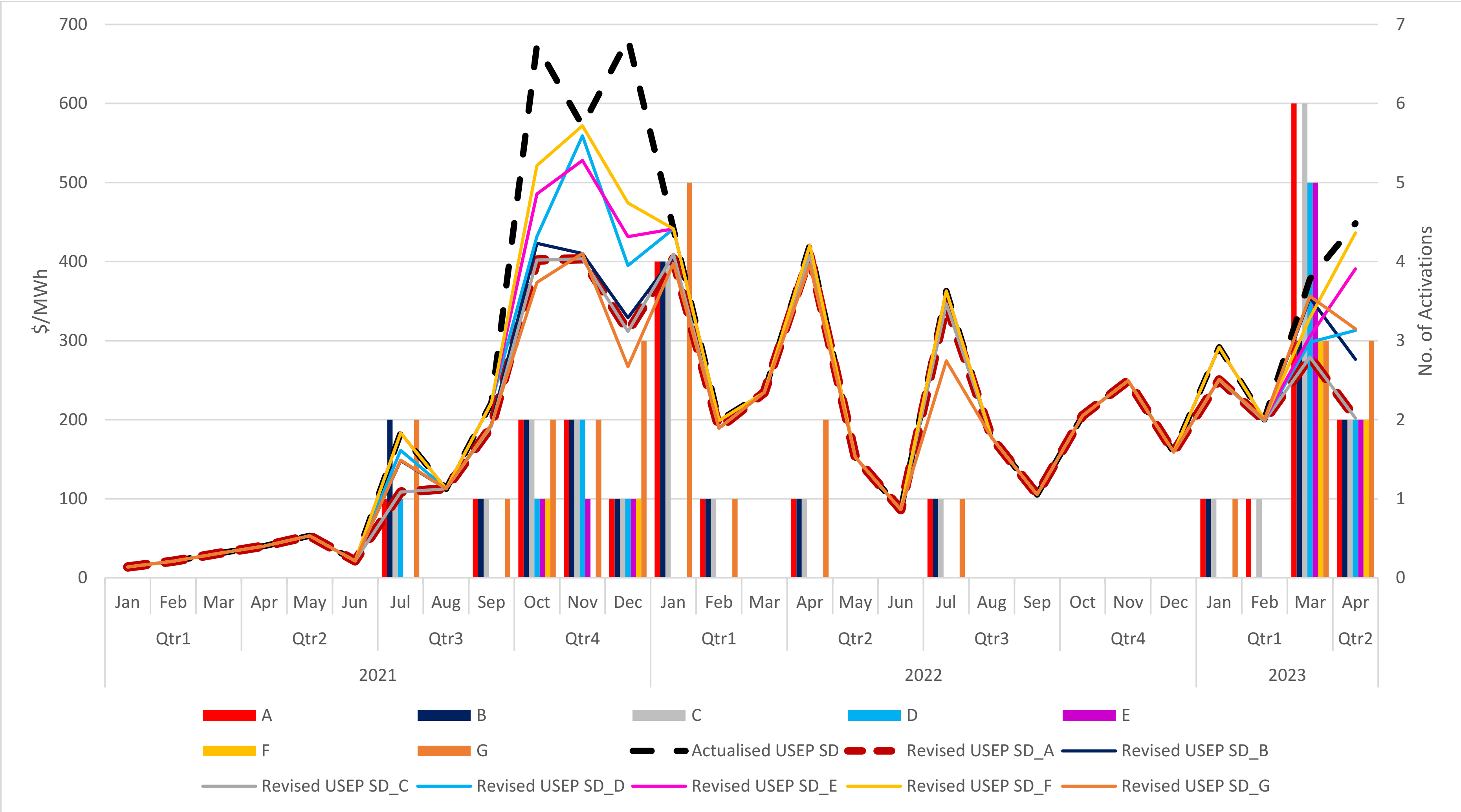


Table A2-2: Simulation Summary Statistics for Scenarios A – G for Period 1 (Jan 21 – Sep 22)

Scenario	No. of Activations	TPs with TPC in place		TPs with USEP above (i.e. capped at) TPC when TPC is in place		SD of USEP across Activations** ($/MWh)		Average % reduction in USEP due to TPC***	Activation before 2H 2021
		No. of TPs	% of total TPs*	No. of TPs	% of total TPs*	Without TPC	With TPC in place		
A	14	1118	3.7%	487	1.6%	801	576	7.7%	No
B	15	1106	3.6%	414	1.4%	774	569	6.4%	No
C	14	1027	3.4%	480	1.6%	812	594	7.6%	No
D	5	828	2.7%	313	1.0%	830	614	5.2%	No
E	3	662	2.2%	269	0.9%	921	702	4.6%	No
F	2	665	2.2%	227	0.7%	943	729	3.6%	No
G	19	1362	4.4%	504	1.6%	732	510	8.1%	No

* Based on total number of TPs from Jan 2021 to Sep 2022 (i.e. 30,624 TPs).

** Based on the SD of USEP in the periods with TPC activated.

*** Based on the % reduction in average USEP from Jan 2021 to Sep 2022 due to the effect of the TPC mechanism.

Table A2-3: Simulation Summary Statistics for Scenarios A – G for Period 2 (Oct 22 – Apr 23)

Scenario	No. of Activations	TPs with TPC in place		TPs with USEP above (i.e. capped at) TPC when TPC is in place		SD of USEP across Activations** ($/MWh)		Average % reduction in USEP due to TPC***	Activation before 2H 2021
		No. of TPs	% of total TPs*	No. of TPs	% of total TPs*	Without TPC	With TPC in place		
A	10	711	7.0%	345	3.4%	611	390	7.1%	No
B	6	433	4.3%	70	0.7%	670	503	3.7%	No
C	10	671	6.6%	340	3.3%	624	402	7.0%	No
D	7	754	7.4%	325	3.2%	510	360	5.2%	No
E	7	798	7.8%	347	3.4%	503	399	4.2%	No
F	5	671	6.6%	315	3.1%	505	426	3.2%	No
G	7	433	4.3%	62	0.6%	720	530	3.2%	No

* Based on total number of TPs from Oct 2022 to Apr 2023 (i.e. 10,176 TPs).

** Based on the SD of USEP in the periods with TPC activated.

*** Based on the % reduction in average USEP from Oct 2022 to Apr 2023 due to the effect of the TPC mechanism.

Table A2-4: SD of USEP for each Activation under Scenarios A – C

Activation No.	Scenario A			Scenario B			Scenario C		
	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)
1	25 Jul-28 Jul 21	421	227	25 Jul-27 Jul 21	381	330	25 Jul-28 Jul 21	421	227
2	22 Sep-24 Sep 21	565	461	26 Jul-28 Jul 21	430	282	22 Sep-24 Sep 21	578	473
3	09 Oct-11 Oct 21	822	748	22 Sep-24 Sep 21	565	464	09 Oct-10 Oct 21	832	759
4	11 Oct-17 Oct 21	914	335	09 Oct-11 Oct 21	822	752	11 Oct-17 Oct 21	914	335
5	25 Nov-27 Nov 21	1257	802	11 Oct-17 Oct 21	914	366	25 Nov-27 Nov 21	1257	802
6	28 Nov-03 Dec 21	1277	531	25 Nov-27 Nov 21	1257	806	28 Nov-03 Dec 21	1277	531
7	07 Dec-10 Dec 21	931	464	28 Nov-03 Dec 21	1277	548	07 Dec-10 Dec 21	931	464
8	16 Jan-18 Jan 22	528	467	07 Dec-10 Dec 21	931	472	16 Jan-18 Jan 22	514	510
9	17 Jan-19 Jan 22	657	577	16 Jan-18 Jan 22	528	470	17 Jan-19 Jan 22	683	651
10	22 Jan-24 Jan 22	493	487	17 Jan-19 Jan 22	657	581	22 Jan-23 Jan 22	523	523
11	29 Jan-31 Jan 22	791	582	22 Jan-24 Jan 22	493	488	29 Jan-31 Jan 22	798	587
12	04 Feb-06 Feb 22	554	514	29 Jan-31 Jan 22	791	585	04 Feb-05 Feb 22	598	556
13	24 Apr-26 Apr 22	875	807	04 Feb-06 Feb 22	554	514	24 Apr-26 Apr 22	883	814
14	16 Jul-18 Jul 22	1131	1061	24 Apr-26 Apr 22	875	807	16 Jul-18 Jul 22	1158	1088
15	08 Jan-10 Jan 23	836	654	16 Jul-18 Jul 22	1131	1062	08 Jan-10 Jan 23	907	711
16	19 Feb-21 Feb 23	589	585	08 Jan-10 Jan 23	589	585	19 Feb-21 Feb 23	628	624
17	15 Mar-17 Mar 23	482	478	20 Mar-22 Mar 23	813	701	15 Mar-17 Mar 23	492	488
18	20 Mar-22 Mar 23	793	365	23 Mar-25 Mar 23	471	415	20 Mar-22 Mar 23	793	365
19	23 Mar-25 Mar 23	412	293	26 Mar-28 Mar 23	467	460	23 Mar-25 Mar 23	412	293
20	26 Mar-28 Mar 23	469	370	12 Apr-15 Apr 23	859	469	26 Mar-28 Mar 23	469	370
21	28 Mar-30 Mar 23	422	288	24 Apr-28 Apr 23	820	385	28 Mar-30 Mar 23	424	290

Activation No.	Scenario A			Scenario B			Scenario C		
	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)
22	30 Mar-01 Apr 23	492	438				30 Mar-01 Apr 23	503	448
23	12 Apr-15 Apr 23	828	258				12 Apr-15 Apr 23	828	258
24	24 Apr-29 Apr 23	784	173				24 Apr-29 Apr 23	784	173

Refers to the time period from the start of the MAP till the end of the TPC activation.

*Table A2-5: SD of USEP for each Activation under Scenarios D – F**

Activation No.	Scenario D			Scenario E			Scenario F		
	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)
1	24 Jul-29 Jul 21	373	329	07 Oct-19 Oct 21	870	603	06 Oct-20 Oct 21	840	645
2	09 Oct-18 Oct 21	924	535	25 Nov-06 Dec 21	1124	743	24 Nov-08 Dec 21	1047	812
3	24 Nov-29 Nov 21	921	887	06 Dec-12 Dec 21	769	761	16 Mar-24 Mar 23	540	515
4	27 Nov-05 Dec 21	1161	625	16 Mar-23 Mar 23	531	429	17 Mar-28 Mar 23	499	410
5	05 Dec-11 Dec 21	772	692	19 Mar-26 Mar 23	525	358	22 Mar-30 Mar 23	413	213
6	18 Mar-24 Mar 23	557	394	22 Mar-29 Mar 23	400	296	09 Apr-20 Apr 23	523	512
7	22 Mar-26 Mar 23	355	243	24 Mar-30 Mar 23	429	337	20 Apr-30 Apr 23	551	479
8	24 Mar-28 Mar 23	437	361	26 Mar-01 Apr 23	463	401			
9	26 Mar-30 Mar 23	445	309	09 Apr-18 Apr 23	587	499			
10	28 Mar-01 Apr 23	460	351	21 Apr-30 Apr 23	586	474			
11	10 Apr-16 Apr 23	691	469						
12	22 Apr-30 Apr 23	628	392						

***** The last activation for Scenarios D-F has yet to Off-Trigger by P48, 30 Apr 2023.

Refers to the time period from the start of the MAP till the end of the TPC activation.

Table A2-6: SD of USEP for each Activation under Scenario G

Activation No.	Scenario G		
	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)
1	25 Jul-27 Jul 21	390	335
2	26 Jul-28 Jul 21	431	276
3	22 Sep-24 Sep 21	565	464
4	08 Oct-11 Oct 21	811	605
5	10 Oct-17 Oct 21	920	288
6	25 Nov-27 Nov 21	1257	806
7	28 Nov-03 Dec 21	1276	534
8	06 Dec-08 Dec 21	591	472
9	07 Dec-10 Dec 21	884	130
10	16 Dec-18 Dec 21	343	301
11	09 Jan-11 Jan 22	611	549
12	16 Jan-18 Jan 22	528	470
13	17 Jan-19 Jan 22	657	581
14	22 Jan-24 Jan 22	493	488
15	29 Jan-31 Jan 22	791	585
16	04 Feb-06 Feb 22	554	514
17	04 Apr-06 Apr 22	761	678
18	24 Apr-26 Apr 22	875	807
19	16 Jul-18 Jul 22	1177	808
20	08 Jan-10 Jan 23	836	656
21	20 Mar-22 Mar 23	813	702

Activation No.	Scenario G		
	Time Period#	SD (no TPC) ($/MWh)	SD (with TPC) ($/MWh)
22	23 Mar-25 Mar 23	473	429
23	26 Mar-28 Mar 23	466	466
24	12 Apr-14 Apr 23	906	620
25	13 Apr-15 Apr 23	726	391
26	24 Apr-28 Apr 23	822	447

Refers to the time period from the start of the MAP till the end of the TPC activation.

Appendix 3 – Framework and Methodology to Determine Spot LRMC and Term LRMC for the Temporary Price Cap Mechanism

1 Context

a. The TPC mechanism consists of two key parameters, viz. the TPC and Moving Average Price Threshold ("**MAPT**"). In the first instance, both parameters will be set with reference to the long run marginal cost ("**LRMC**") of combined cycle gas turbine ("**CCGT**") generation units ("**CCGT LRMC**").

b. The CCGT LRMC consist of fuel (including fuel-related) and non-fuel cost components. To account for the prevailing marginal cost of fuel, EMA will on a bi-weekly basis update the CCGT LRMC using the higher of either: (a) spot gas prices based on the Japan-Korea Marker ("**JKM**") ("**Spot LRMC**"), or (b) term gas prices under specified Gas Supply Agreements ("**GSAs**") for commercial power generation ("**Term LRMC**").

c. The framework/methodology that EMA will adopt to determine the Spot LRMC and Term LRMC for the purpose of the TPC mechanism is set out below.

2 Non-fuel cost component of the Spot LRMC and Term LRMC

a. The non-fuel cost component of the LRMC under the Vesting Contracts for hedging and setting the regulated tariff for non-contestable consumer load is benchmarked to the most efficient CCGT technology that accounts for at least 25% of the system demand in Singapore.

b. The non-fuel cost component of both the Spot LRMC and Term LRMC, and in turn the CCGT LRMC, will be aligned to the non-fuel cost component of the LRMC under the Vesting Contracts. More specifically, the <u>prevailing Non-Fuel LRMC Parameters for setting the Base Vesting Price ("**BVP**")</u> under the Vesting Contracts, will be used to set the non-fuel cost component of the Spot LRMC and Term LRMC for the purpose the TPC mechanism.

c. Refer to the ***Vesting Contracts Procedures (section 3.2.2 and 3.2.3***) for the detailed methodology to determine the Non-Fuel LRMC Parameters (including carbon price) for the BVP.

3 Updating fuel cost component of Spot LRMC and Term LRMC

a. The fuel cost component of the Spot LRMC will be updated <u>bi-weekly</u> to reflect the prevailing <u>spot gas price</u> for power generation. More specifically, the fuel cost component will be <u>updated ex ante and fixed</u> for each half-month period, specifically the 1st day to 15th day (i.e. first-half or "**1H**") of each calendar month, and the 16th day to the last day (i.e. second-half or "**2H**") of the month.

b. The fuel cost component of the Term LRMC will be updated monthly to reflect the term gas price for power generation. More specifically, the fuel cost component will be updated ex ante and fixed for each month.

4 Spot LRMC: Fuel cost component

a. The fuel cost component of the Spot LRMC will consist of the following parameters:

   i. Spot Hydrocarbon Charge;

   ii. LNG Terminal Charge;

   iii. Gas Pipeline Transportation Charge; and

   iv. Any other applicable fees or charges approved by EMA.[9]

b. Due to the lead-time of 5 business days required by EMC to publish and effect any change in the TPC parameters in the SWEM, EMA will update the fuel cost parameters for each half-month period (i.e. 1H or 2H of the month) using available data up to and including 7 business days before the start of the relevant half-month period ("**Spot Determination Date**").

c. ***Spot Hydrocarbon Charge*** for each half-month period (i.e. 1H or 2H of a given month '*M*') will be set based on:

   i. The average of the daily JKM prices (in US$/mmbtu) available and as published in the Platts LNG Daily (*Platts product code: AAOVQ00*) across the period covering the 30 consecutive calendar days preceding the Spot Determination Date and including the Spot Determination Date ("**Spot Assessment Period**"); and

   ii. The average of the daily spot US$ to S$ *ask* exchange rates (*reference code: SGD Curncy*) available and quoted by Bloomberg Generic (*reference code: BGN*) at New York 17:00 across the Spot Assessment Period.[10]

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[9] The cost of Lost and Unaccounted for Gas ("**LUFG**") is excluded for determining CCGT LRMC for the purpose of the TPC mechanism. Such cost is relatively small and would have insignificant impact for the purpose of the TPC mechanism.

[10] For example, to set the Spot LRMC for 1H of July 2023, the Spot Determination Date is 21 Jun 2023, and the Spot Assessment Period is from 23 May 2023 to 21 Jun 2023 (both dates inclusive).

d. ***LNG Terminal Charge*** will be fixed for each month '*M*' based on the sum of the Reservation Charge and Utilisation Charge for the month '*M*' as published by Singapore LNG Corporation Pte Ltd ("**SLNG**") on the date which is 7 business days before the start of the month '*M*'.

e. ***Gas Pipeline Transportation Charge*** will be fixed for each Financial Year ("**FY**") ending 31 Mar based on the efficient cost approved by EMA to be recovered by the Gas Transporter (viz. PowerGas) for transporting regasified LNG for the FY.

5 Term LRMC: Fuel cost component

a. The fuel cost component of Term LRMC will consist of the following parameters:

    i. Term Hydrocarbon Charge under GSAs that meet certain conditions ("**Specified GSAs**");

    ii. LNG Terminal Charge;

    iii. Gas Pipeline Transportation Charge; and

    iv. Any other applicable fees or charges approved by EMA.[11]

b. Due to the lead-time of 5 business days required by EMC to publish and effect any change in the TPC parameters in the SWEM, EMA will update the fuel cost parameters for a given month '*M*' using available data up to and including 7 business days before the start of the month '*M*' ("**Term Determination Date**").

c. A ***Specified GSA*** that EMA will include to determine the fuel cost component of Term LRMC for a given month '*M*', refers to a GSA that meets the following conditions:

    i. Under the GSA, a Genco is the buyer of the gas to be supplied under the GSA for commercial power generation;

    ii. The GSA has a contract duration of 1 year or longer;

    iii. The GSA has a Daily Contracted Quantity ("**DCQ**") of 10 billion British thermal units per day ("**Bbtud**") or more for the majority (i.e. at least 50%) of the month '*M*'; and

[11] The cost of LUFG is excluded for determining CCGT LRMC for the purpose of the TPC mechanism. Such cost is relatively small and would have insignificant impact for the purpose of the TPC mechanism.

iv. The GSA is in contractual force to supply gas for the majority (i.e. at least 50%) of the month ‘*M*’.

d. ***Term Hydrocarbon Charge*** for a given month ‘*M*’ will be set based on:

i. For a Specified GSA with hydrocarbon price formula indexed to High Sulphur Fuel Oil (“**HSFO**”) or Dated Brent prices in the preceding month ‘*M-1*’:

1. the average of the daily *closing* prices of HSFO (in US$/MT) (*Platts product code: PUADV00*) or Dated Brent (in US$/bbl) (*Platts product code: PCAAS00*) as published by Platts respectively across the period covering the 1st day of month ‘*M-1*’ up to and including the Term Determination Date (“**Term Assessment Period 1**”); and

2. the average of the daily spot US$ to S$ *ask* exchange rates (*reference code: SGD Curncy*) available and quoted by Bloomberg Generic (*reference code: BGN*) at New York 17:00 across the Term Assessment Period 1.[12]

ii. For a Specified GSA with hydrocarbon price formula indexed to HSFO or Dated Brent prices in month ‘*M*’:

1. the average of the daily *closing* 1-month forward HSFO price (in US$/MT) (*Platts product code: PUAXZ00*) or Dated Brent (in US$/bbl) (*Platts product code: BDLM001*) for month ‘*M*’ as published by Platts respectively across the Term Assessment Period 1; and

2. the average of daily outright 1-month forward US$ to S$ *ask* exchange rates (*reference code: SGD1M BGN Curncy*) available and quoted by Bloomberg Generic (*reference code: BGN*) for month ‘*M*’ across the Term Assessment Period 1.

iii. For a Specified GSA with hydrocarbon price formula indexed to JKM prices:

1. The average of the daily JKM prices (in US$/mmbtu) available and as published in the Platts LNG Daily (*Platts product code: AAOVQ00*) across the assessment period as defined within the specified GSA; and

[12] For example, to set the Term LRMC for Aug 2023, for such Specified GSA, the Term Determination Date is 21 Jul 2023, and the Term Assessment Period 1 is from 1 Jul 2023 to 21 Jul 2023 (both dates inclusive).

2. The average of the daily spot US$ to S$ ask exchange rates (*reference code: SGD Curncy*) available and quoted by Bloomberg Generic (*reference code: BGN*) at New York 17:00 across the assessment period as defined within the specified GSA.

iv. For a Specified GSA with hydrocarbon price formula indexed to Dated Brent prices in the preceding 3 month (i.e. month '*M-3*' to '*M-1*'):

1. the average of the daily closing prices of Dated Brent (in US$/bbl) (*Platts product code: PCAAS00*) as published by Platts across the period covering the 1st day of month '*M-3*' up to and including the Term Determination Date ("**Term Assessment Period 2**"); and

2. the average of the daily spot US$ to S$ *ask* exchange rates (*reference code: SGD Curncy*) available and quoted by Bloomberg Generic (*reference code: BGN*) at New York 17:00 across the Term Assessment Period 2.[13]

v. The volume-weighted average (taking into account the respective DCQ) of the Term Hydrocarbon Charge as determined above for all the Specified GSAs.

e. ***LNG Terminal Charge*** will be fixed for each month '*M*' based on the sum of the Reservation Charge and Utilisation Charge for the month '*M*' as published by SLNG on the date which is 7 business days before the start of the month '*M*', and prorated using the total DCQ of regasified LNG as a percentage of total DCQ of regasified LNG and PNG under the Specified GSAs.

f. ***Gas Pipeline Transportation Charge*** will be fixed for each FY ending 31 Mar for the Gas Transporter (viz. PowerGas) to recover the efficient cost approved by EMA for transporting regasified LNG and PNG for the FY.

[13] For example, to set the Term LRMC for Aug 2023, for such Specified GSA, the Term Determination Date is 21 Jul 2023, and the Term Assessment Period 2 is from 1 May 2023 to 21 Jul 2023 (both dates inclusive).

Appendix 4 – Market Rule Amendments

Existing Market Rules	Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)	Remarks
CHAPTER 3	**CHAPTER 3**	
[New section]	**3.11B COMPENSATION IN RELATION TO THE TEMPORARY PRICE CAP MECHANISM** 3.11B.1 Where a *market participant* makes a request for compensation under section N.3.5 of Appendix 6N, the *market participant* shall (i) set out the *market participant*'s proposed amount of compensation together with the requisite supporting documents, and (ii) make such request no later than 8 weeks after the *dispatch period* where the *temporary price cap* has ceased to apply as communicated by the *EMC* by means of electronic communications. The *Authority* will take into consideration the *market participant*'s proposal to determine the final compensation. The *EMC* shall pay the *market participant* the final compensation amount according to section 3.12.	To allow for compensation when the temporary price cap is active and market participants are unable to recover their actual costs of supply in those periods.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
CHAPTER 6	**CHAPTER 6**	
APPENDIX 6D – SECTION C: LINEAR PROGRAM	**APPENDIX 6D – SECTION C: LINEAR PROGRAM**	
D.24 PRICE FORMATION D.24.1.1 For *generation registered facilities* that are not *multi-unit facilities*, and for *generation settlement facilities* that are not *pseudo generation settlement facilities*, represented as *synchronised* in the *dispatch network data* or connected to the dispatch network in accordance with section D.6.5 in the *dispatch period*, the *market energy price* shall be calculated as follows: … The price MEP^m shall then be further modified in accordance with section D.24.5.	**D.24 PRICE FORMATION** D.24.1.1 For *generation registered facilities* that are not *multi-unit facilities*, and for *generation settlement facilities* that are not *pseudo generation settlement facilities*, represented as *synchronised* in the *dispatch network data* or connected to the dispatch network in accordance with section D.6.5 in the *dispatch period*, the *market energy price* shall be calculated as follows: … The price MEP^m shall then be further modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	To establish how the USEP and respective prices will be calculated with respect to whether the temporary price cap is in effect or otherwise.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
D.24.1.2 For *generation registered facilities* that are *multi-unit facilities* represented as *synchronised* in the *dispatch network data* or connected to the dispatch network in accordance with section D.6.5 in the *dispatch period*, the *market energy prices* shall be calculated as follows: $\text{MEP}^{m(g)} = \dfrac{\sum_{u \in \text{CONNECTEDUNITS}_g} \left(\text{Proportion}_u \times \text{EnergyPrice}_{n(u)}\right)}{\sum_{u \in \text{CONNECTEDUNITS}_g} \text{Proportion}_u}$ … The price MEP^m shall then be further modified in accordance with section D.24.5.	D.24.1.2 For *generation registered facilities* that are *multi-unit facilities* represented as *synchronised* in the *dispatch network data* or connected to the dispatch network in accordance with section D.6.5 in the *dispatch period*, the *market energy prices* shall be calculated as follows: $\text{MEP}^{m(g)} = \dfrac{\sum_{u \in \text{CONNECTEDUNITS}_g} \left(\text{Proportion}_u \times \text{EnergyPrice}_{n(u)}\right)}{\sum_{u \in \text{CONNECTEDUNITS}_g} \text{Proportion}_u}$ … The price MEP^m shall then be further modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
D.24.1.3 For *pseudo generation settlement facilities*, the *market energy price* shall be calculated as follows: … where: $MEP^{m(g)}$ is the *market energy price* for *market network node m* corresponding to the *generation registered facility* that *energy offer g* is for calculated in sections D.24.1.1 or D.24.1.2 after it has been modified in accordance with section D.24.5.	D.24.1.3 For *pseudo generation settlement facilities*, the *market energy price* shall be calculated as follows: … where: $MEP^{m(g)}$ is the *market energy price* for *market network node m* corresponding to the *generation registered facility* that *energy offer g* is for calculated in sections D.24.1.1 or D.24.1.2 after it has been modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	
D.24.2 Nodal spot prices for *dispatch network nodes* or NSP_n shall be calculated from the values of $EnergyPrice_n$, the dual variables corresponding to constraint D.16.1.2 for the relevant *dispatch network node*, and then further modified in accordance with section D.24.5.	D.24.2 Nodal spot prices for *dispatch network nodes* or NSP_n shall be calculated from the values of $EnergyPrice_n$, the dual variables corresponding to constraint D.16.1.2 for the relevant *dispatch network node*, and then further modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
[New Section]	D.24.2A Reference nodal spot prices for *dispatch network nodes* or $RNSP_n$ shall be calculated from the values of $\mathsf{EnergyPrice}_n$, the dual variables corresponding to constraint D.16.1.2 for the relevant *dispatch network node*, and then further modified in accordance with section D.24.5.	
D.24.3 *Reserve* prices for each *reserve* class shall be calculated from the values of $\mathsf{ReservePrice}_c$, the dual variables corresponding to constraint D.17.3.4, and then further modified in accordance with section D.24.5.	D.24.3 *Reserve* prices for each *reserve* class shall be calculated from the values of $\mathsf{ReservePrice}_c$, the dual variables corresponding to constraint D.17.3.4, and then further modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	
D.24.4 The *market regulation price* or *MFP* shall be calculated from the values of $\mathsf{RegulationPrice}$, the dual variable corresponding to constraint D.18.2.1, and then further modified in accordance with section D.24.5.	D.24.4 The *market regulation price* or *MFP* shall be calculated from the values of $\mathsf{RegulationPrice}$, the dual variable corresponding to constraint D.18.2.1, and then further modified in accordance with section D.24.5 for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.5A for *dispatch periods* where the *temporary price cap* is in effect.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
D.24.5 The market clearing engine shall produce the following modified prices corresponding to the prices referred to in sections D.24.1 to D.24.4 for each dispatch period: D.24.5.1 if the price referred to any of sections D.24.1 to D.24.4 is between the applicable upper and lower limits specified in Appendix 6J section J.1, then the modified price shall equal that price; D.24.5.2 if the price referred to any of sections D.24.1 to D.24.4 exceeds the applicable upper limit specified in Appendix 6J section J.1, then the modified price shall be set to that upper limit; and D.24.5.3 if the price referred to any of sections D.24.1 to D.24.4 is below the applicable lower limit specified in Appendix 6J section J.1, then the modified price shall be set to that lower limit.	D.24.5 The market clearing engine shall produce the following modified prices corresponding to the prices referred to in sections D.24.1 to D.24.4 for each dispatch period: D.24.5.1 if the price referred to any of sections D.24.1 to D.24.4 is between the applicable upper and lower limits specified in Appendix 6J section ~~J.1~~ J.1.7, then the modified price shall equal that price; D.24.5.2 if the price referred to any of sections D.24.1 to D.24.4 exceeds the applicable upper limit specified in Appendix 6J section ~~J.1~~ J.1.7, then the modified price shall be set to that upper limit; and D.24.5.3 if the price referred to any of sections D.24.1 to D.24.4 is below the applicable lower limit specified in Appendix 6J section ~~J.1~~ J.1.7, then the modified price shall be set to that lower limit.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
[New Section]	D.24.5A If the *temporary price cap* as referred to in section N.3.1 of Appendix 6N is activated, notwithstanding section D.24.5, the *market clearing engine* shall apply the upper and lower limits under Appendix 6J, section J.1.7A in its determination of modified prices as referred to in D.24.1 to D.24.4 for each *dispatch period* the *temporary price cap* is active for. For the avoidance of doubt, the upper limits under section J.1.7A of Appendix 6J shall not be applied in the determination of the $RNSP_n$ as referred to in D.24.2A.	

<table>
<tr><th>Existing Market Rules</th><th>Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)</th><th>Remarks</th></tr>
<tr><td>D.24.6 The market clearing engine shall, for each dispatch period, determine the uniform Singapore energy price for the settlement interval corresponding to that dispatch period in accordance with the following formula:

USEP = uniform Singapore energy price
= $\Sigma_n (W^n \times NSP^n) / \Sigma_n W^n$
where:
$\{n \mid n \in \text{NODES}\}$

$$W^n = \sum_{\substack{p \in \text{ENERGYBIDS}_n,\\ p \notin \text{INTERTIEENERGYBIDS}}} \text{Purchase}_p - \sum_{j \in \text{DEFICITGENERATIONBLOCKS}_n} \text{DeficitGenerationBlock}_{n,j}$$

NSP^n = the nodal spot price for DNN n referred to in section D.24.2 after it has been modified in accordance with section D.24.5.</td><td>D.24.6 The market clearing engine shall, for each dispatch period, determine the uniform Singapore energy price for the settlement interval corresponding to that dispatch period in accordance with the following formula:

USEP = uniform Singapore energy price
= $\Sigma_n (W^n \times NSP^n) / \Sigma_n W^n$
where:
$\{n \mid n \in \text{NODES}\}$

$$W^n = \sum_{\substack{p \in \text{ENERGYBIDS}_n,\\ p \notin \text{INTERTIEENERGYBIDS}}} \text{Purchase}_p - \sum_{j \in \text{DEFICITGENERATIONBLOCKS}_n} \text{DeficitGenerationBlock}_{n,j}$$

NSP^n = the nodal spot price for DNN n referred to in section D.24.2 after it has been modified in accordance with section D.24.5 or<u> section D.24.5A where applicable.</u></td><td></td></tr>
</table>

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
[New Section]	D.24.6A The *market clearing engine* shall, for each *dispatch period*, determine the *reference uniform Singapore energy price* or *RUSEP* corresponding to that *dispatch period* in accordance with the following formula: RUSEP = *reference uniform Singapore energy price* = $\Sigma_n (W^n \times RNSP^n) / \Sigma_n W^n$ where: $\{n \mid n \in \text{NODES}\}$ $W^n = \sum_{p \in \text{ENERGYBIDS}_n, p \notin \text{INTERTIEENERGYBIDS}} \text{Purchase}_p - \sum_{j \in \text{DEFICITGENERATIONBLOCKS}_n} \text{DeficitGenerationBlock}_{n,j}$ $RNSP^n$ = the nodal spot price for *DNN* n referred to in section D.24.2A after it has been modified in accordance with section D.24.5.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
D.24.7 The *market clearing engine* shall, for each *dispatch period*, determine the *market reserve price* or MRP_x for each *reserve provider group x*, in accordance with the following formula: … ReservePrice_c = the *reserve class* price referred to in section D.24.3 after it has been modified in accordance with section D.24.5.	D.24.7 The *market clearing engine* shall, for each *dispatch period*, determine the *market reserve price* or MRP_x for each *reserve provider group x*, in accordance with the following formula: … ReservePrice_c = the *reserve class* price referred to in section D.24.3 after it has been modified in accordance with section D.24.5 <u>or section D.24.5A where applicable.</u>	
D.24.8 The *market clearing engine* shall, for each *dispatch period* for which the linear program was re-solved pursuant to section D.22A, determine the counterfactual *uniform Singapore energy price*, or CUSEP, for the *settlement interval* corresponding to that *dispatch period* in accordance with the formula in section D.24.6, subject to section D.24.9.	D.24.8 The *market clearing engine* shall, for each *dispatch period* for which the linear program was re-solved pursuant to section D.22A, determine the counterfactual *uniform Singapore energy price*, or CUSEP, for the *settlement interval* corresponding to that *dispatch period* in accordance with the formula in section D.24.6 <u>for *dispatch periods* where the *temporary price cap* is not in effect, or in accordance with section D.24.6A for *dispatch periods* where the *temporary price cap* is in effect</u>, subject to section D.24.9.	
D.24.9 If, for any *settlement interval*, D.24.9.1 $CUSEP_h = USEP_h = 0.9 \times VoLL$; and	D.24.9 If, for any *settlement interval* <u>where the *temporary price cap* is not in effect,</u> D.24.9.1 $CUSEP_h = USEP_h = 0.9 \times VoLL$; and	To establish treatment of the CUSEP and hence the LCP

Existing Market Rules	Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)	Remarks
D.24.9.2 shortfalls in *energy* were scheduled in the counterfactual solution referred to in D.22A for the corresponding *dispatch period*, then the value of $CUSEP_h$ shall be further modified and set to 1×*VoLL*.	D.24.9.2 shortfalls in *energy* were scheduled in the counterfactual solution referred to in D.22A for the corresponding *dispatch period*, then the value of $CUSEP_h$ shall be further modified and set to 1×*VoLL*.	when the TPC is in effect.
Explanatory Note: The CUSEP is modified in an energy shortfall situation to better reflect the value of dispatchable load that was voluntarily curtailed by LRFs with REB.		
[New Section]	D.24.9A If, for any *settlement interval* where the *temporary price cap* is in effect, D.24.9A.1 $CUSEP_h$ = $RUSEP_h$ = 0.9×*VoLL*; and D.24.9A.2 shortfalls in *energy* were scheduled in the counterfactual solution referred to in D.22A for the corresponding *dispatch period*, then the value of $CUSEP_h$ shall be further modified and set to 1×*VoLL*.	
	Explanatory Note: The CUSEP is modified in an energy shortfall situation to better reflect the value of dispatchable load that was voluntarily curtailed by LRFs with REB.	

<table>
<tr><td>Existing Market Rules</td><td>Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)</td><td>Remarks</td></tr>
<tr><td>APPENDIX J – PRICE LIMITS AND CONSTRAINT VIOLATION PENALTIES</td><td>APPENDIX J – PRICE LIMITS AND CONSTRAINT VIOLATION PENALTIES</td><td></td></tr>
<tr><td>
<u>J.1 MAXIMUM AND MINIMUM PRICES</u>
J.1.2 The upper limit on energy prices in standing offers, offer variations and settlements, and the upper limit on load curtailment prices shall be:
EnergyPriceMax
…
J.1.7 Price Bound Values:
<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>EnergyPriceMin</td><td>0.9 *CDC</td></tr>
<tr><td>REBPriceMin</td><td>1.5 * BVP</td></tr>
<tr><td>EnergyPriceMax</td><td>0.9* VoLL</td></tr>
<tr><td>REBPriceMax</td><td>1.00 * VoLL</td></tr>
<tr><td>RegPriceMax</td><td>0.06 * VoLL</td></tr>
<tr><td>ResPriPriceMax</td><td>0.85 * VoLL</td></tr>
<tr><td>ResConPriceMax</td><td>0.65 * VoLL</td></tr>
</table>
</td><td>
<u>J.1 MAXIMUM AND MINIMUM PRICES</u>
J.1.2 The upper limit on energy prices in <s>standing offers, offer variations and</s> settlements<s>, and the upper limit on load curtailment prices</s> shall be:
EnergyPriceMax
<u>J.1.2B The upper limit on load curtailment prices shall be:</u>
<u>LoadCurtailmentPriceMax</u>
<u>J.1.2C The upper limit on energy prices in standing offers and offer variations shall be:</u>
<u>EnergyOfferMax</u>
…
J.1.7 Price Bound Values:
<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>EnergyPriceMin</td><td>0.9 * CDC</td></tr>
<tr><td>REBPriceMin</td><td>1.5 * BVP</td></tr>
<tr><td>EnergyPriceMax</td><td>0.9 * VoLL</td></tr>
<tr><td><u>LoadCurtailmentPrice Max</u></td><td><u>0.9 * VoLL</u></td></tr>
</table>
</td><td>To establish the price bound values when the temporary price cap is in effect, and make modifications to the price bound values when the temporary price cap is not in effect.</td></tr>
</table>

<table>
<tr><th>Existing Market Rules</th><th>Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)</th><th>Remarks</th></tr>
<tr><td></td><td>
<table>
<tr><td>EnergyOfferMax</td><td>0.9 * VoLL</td></tr>
<tr><td>REBPriceMax</td><td>1.00 * VoLL</td></tr>
<tr><td>RegPriceMax</td><td>0.06 * VoLL</td></tr>
<tr><td>ResPriPriceMax</td><td>0.85 * VoLL</td></tr>
<tr><td>ResConPriceMax</td><td>0.65 * VoLL</td></tr>
</table>

J.1.7A Price Bound Values that will apply if the temporary price cap is in effect:

<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>EnergyPriceMin</td><td>0.9*CDC</td></tr>
<tr><td>REBPriceMin</td><td>1.5 * BVP</td></tr>
<tr><td>EnergyPriceMax</td><td>Min [TPC Energy Multiplier* TPC Price Parameter, 0.9* VoLL]</td></tr>
<tr><td>LoadCurtailmentPriceMax</td><td>0.9* VoLL</td></tr>
<tr><td>EnergyOfferMax</td><td>0.9 * VoLL</td></tr>
</table>
</td><td>The TPC Energy Multiplier and TPC Price Parameter refers to the Multiplier and CCGT LRMC parameters respectively as defined within the TPC Final</td></tr>
</table>

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
	<table><tr><td>REBPriceMax</td><td>1.00*VoLL</td></tr><tr><td>RegPriceMax</td><td>*TPC Regulation Multiplier* * EnergyPriceMax</td></tr><tr><td>ResPriPriceMax</td><td>*TPC Primary Reserve Multiplier* * EnergyPriceMax</td></tr><tr><td>ResConPriceMax</td><td>*TPC Contingency Reserve Multiplier* * EnergyPriceMax</td></tr></table>	Determination Paper. The TPC Regulation Multiplier, TPC Primary Reserve Multiplier and TPC Contingency Reserve Multiplier are variable ratios to ensure that the Regulation, Primary Reserves and Contingency Reserves Price Cap will be reduced in proportion when the TPC is applied, as determined in the TPC Final

<table>
<tr><th>Existing Market Rules</th><th>Proposed Changes (Deletions represented by strikethrough text and additions represented by double-underlined text)</th><th>Remarks</th></tr>
<tr><td></td><td></td><td>Determination Paper.</td></tr>
<tr><td>APPENDIX L – CALCULATION OF LOAD CURTAILMENT QUANTITY AND LOAD CURTAILMENT PRICE</td><td>APPENDIX L – CALCULATION OF LOAD CURTAILMENT QUANTITY AND LOAD CURTAILMENT PRICE</td><td></td></tr>
<tr><td>
L.4 LOAD CURTAILMENT PRICE

L.4.1 The load curtailment price (in $/MWh) for a given dispatch period h shall be calculated as:

$$LCP_h = \frac{\mathrm{Max}\left[\left(CUSEP_h - USEP_h\right)\times\frac{1}{3}\times NRQ_h, 0\right]}{\sum_p LCQ_{p,h}}$$

where:

$\sum_p$ = sum over all LRF p

[New Section]

L.4.2 If the load curtailment price (in $/MWh) referred to in section L.4.1 exceeds the applicable upper price limit for energy specified in section J.1.2 of Appendix 6J, then the
</td><td>
L.4 LOAD CURTAILMENT PRICE

L.4.1 The load curtailment price (in $/MWh) for a given dispatch period h where the temporary price cap is not in effect shall be calculated as:

$$LCP_h = \frac{\mathrm{Max}\left[\left(CUSEP_h - USEP_h\right)\times\frac{1}{3}\times NRQ_h, 0\right]}{\sum_p LCQ_{p,h}}$$

where:

$\sum_p$ = sum over all LRF p

L.4.1A The load curtailment price (in $/MWh) for a given dispatch period h where the temporary price cap is in effect shall be calculated as:
</td><td>To establish how the LCP shall be calculated when the temporary price cap is in effect and when it is not in effect.</td></tr>
</table>

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
load curtailment price shall be modified and set to that upper limit. **Explanatory Note: The lower limit on the load curtailment price is zero.**	$$\underline{LCP_h} \;\underline{=}\; \frac{\text{Max}\left[\left(CUSEP_h - RUSEP_h\right)\times\frac{1}{3}\times NRQ_h\ ,0\right]}{\sum_p LCQ_{p,h}}$$ where: $\sum_p$ = sum over all *LRF* p L.4.2 If the *load curtailment price* (in $/MWh) referred to in section L.4.1 and L.4.1A exceeds the applicable upper price limit for ~~energy~~ the *load curtailment price* specified in section J.1.2B of Appendix 6J, then the *load curtailment price* shall be modified and set to that upper limit. **Explanatory Note: The lower limit on the load curtailment price is zero.**	
[New Section]	**APPENDIX N – TEMPORARY PRICE CAP**	
[New Section]	**N.1 PURPOSE** N.1.1 This Appendix sets forth the rules relating to the application of the *temporary price cap* mechanism. This mechanism, when triggered, will result in the application of a *temporary price cap*, where prices will be modified as further described under section D.24.5A of Appendix 6D.	To set forth the design of the TPC mechanism.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
[New Section]	**N.2 DETERMINATION OF THE MOVING AVERAGE PRICE AND MOVING AVERAGE PRICE THRESHOLD** N.2.1 The *moving average price* or *MAP* for each *dispatch period* τ shall be the average of the *RUSEP* as referred to in section D.24.6A of Appendix 6D over the *TPC Trigger Periods.* The *MAP* is calculated as follows: $\mathrm{MAP}_{\tau} = \frac{\sum_{t=\tau-A+1}^{\tau} \mathrm{RUSEP}_{t}}{A}$ Where: A = *TPC Trigger Period* N.2.2 In the event the *market clearing engine* fails to produce any *real-time price schedule* used to determine the prices referred in N.2.1, the *EMC* shall not use the missing *real-time price schedule* for that *dispatch period.* Instead, the *EMC* shall decrease the number of *dispatch period*s in the denominator of the *MAP* by the number of missing *dispatch period*s. N.2.3 The *moving average price threshold* or *MAPT* for each *dispatch period* τ applied under this Appendix 6N shall be determined in accordance with the methodology approved by the *Authority.*	To set forth the Moving Average Price and Moving Average Price Threshold parameters for the activation and de-activation of the temporary price cap mechanism.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
	Explanatory note: **The methodology referred to in this section N.2.3 of Appendix 6N is as published in the Authority's final determination paper titled "Temporary Price Cap Mechanism" dated 16 June 2023.** N.2.4 The *TPC Price Parameter* and any such relevant information to determine the *MAPT* shall be provided to the *EMC* by the *Authority*. The *Authority* may revise the *TPC Price Parameter* and such relevant information from time to time, and such revision shall take effect 5 *business days* after the date of the *EMC*'s receipt of such revision from the *Authority* (or such longer period as may be prescribed by the *Authority*). **Explanatory note:** **Further details on the relevant information to determine the MAPT as referred to in this section N.2.4 of Appendix 6N are published in the Authority's final determination paper titled "Temporary Price Cap Mechanism" dated 16 June 2023.**	
[New Section]	**N.3 APPLICATION OF THE TEMPORARY PRICE CAP MECHANISM** N.3.1 In the event the *moving average price* for a *dispatch period* determined in section N.2.1 exceeds the *moving average price threshold* referred to under section N.2.3 for any *dispatch*	To set forth the on- and off-trigger

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
	period, a *temporary price cap* will apply from the next *dispatch period* for at least the *Minimum Trigger Period*, where revised price limits as referred to under section D.24.5A of Appendix 6D will apply. N.3.2 Upon the occurrence of the event described in section N.3.1, the *EMC* shall, as soon as practicable, issue a notice by means of electronic communications indicating the *dispatch period* from which the *temporary price cap* will take effect. **Explanatory note:** **For a given dispatch period, if the temporary price cap is in effect and the MCE fails to produce a real-time pricing schedule that is reflective of this temporary price cap, the temporary price cap shall be applied for the relevant settlement interval that corresponds to this dispatch period.** N.3.3 The *temporary price cap* will cease to take effect for the *dispatch period* τ_{+1}, provided both the following conditions are met: (i) The *MAP* for the *dispatch period* τ as referred to section N.2.1 is equal to or less than the *moving average price threshold*. This condition is calculated as follows,; $$\frac{MAP_\tau}{MAPT_\tau} \leq 1$$ and	conditions for the TPC mechanism, the TPC level and provisions for compensation.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
	(ii) The *temporary price cap* has been in effect for at least the *Minimum Trigger Period*. N.3.4 If the conditions described in section N.3.3 are met, the *EMC* shall issue a notice, by means of electronic communications stating the *dispatch period* from which the *temporary price cap* will cease to take effect. N.3.5 Where the *temporary price cap* referred to in section N.3.1 is in effect, a *market participant* of a *generation registered facility* or an *import registered facility* that: (a) was issued *dispatch instructions* for *dispatch periods* during which the *temporary price cap* referred to in section N.3.1 was in effect; and (b) failed to recover its actual costs of supply from payments received from the *real-time markets* in respect of those *dispatch periods*, may make a request for compensation in accordance with section 3.11B.1 of Chapter 3.	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
CHAPTER 7	**CHAPTER 7**	
4.1 THE MONTHLY ENERGY UPLIFT CHARGE 4.1.1 Prior to the beginning of each calendar month, the EMC shall calculate for that calendar month the monthly amount for compensation and other payments (MACP), which shall be the sum of: … 4.1.1.4E the compensation amount referred to under section 3.11A of Chapter 3;	**4.1 THE MONTHLY ENERGY UPLIFT CHARGE** 4.1.1 Prior to the beginning of each calendar month, the EMC shall calculate for that calendar month the monthly amount for compensation and other payments (MACP), which shall be the sum of: … 4.1.1.4E the compensation amount referred to under section 3.11A of Chapter 3; … 4.1.1.4G the compensation amount referred to under section 3.11B of Chapter 3;	To establish that any compensation amount arising from the TPC mechanism will be collected under the Monthly Energy Uplift Charge.
CHAPTER 8	**CHAPTER 8**	
[New Section]	**1. DEFINITIONS** 1.1.177 *Minimum Trigger Period* refers to the minimum number of *dispatch periods* the *temporary price cap* will be in effect for as determined by the *Authority*. 1.1.181 *moving average price* or MAP refers to the average of *USEP* across the latest *TPC Trigger Period*, calculated under section N.2.1 of Appendix 6N. 1.1.182 *moving average price threshold* refers to a value used in the assessment of the application of the *temporary price cap*,	To establish new definitions.

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	**Remarks**
	determined by a methodology approved by the *Authority* in accordance with section N.2.3 of Appendix 6N. 1.1.236 *reference uniform Singapore energy price or RUSEP* means the uniform price of energy that applies for the calculation of the *moving average price and the* counterfactual *uniform Singapore energy price* when the *temporary price cap* is in effect. 1.1.297 *temporary price cap* or *TPC* refers to the value that is used to determine the upper limit of *energy* prices when the *moving average price threshold* is reached and is determined in accordance with section J.1.7A of Appendix 6J. 1.1.300 *TPC Energy Multiplier* refers to the multiplier used in the calculation of EnergyPriceMax in accordance with section J.1.7A of Appendix 6J, as determined by the *Authority*. 1.1.301 *TPC Contingency Reserve Multiplier* refers to the multiplier used in the calculation of ResConPriceMax in accordance with section J.1.7A. The multiplier is to ensure the ratio between EnergyPriceMax and ResConPriceMax remains consistent between sections J.1.7 and J.1.7A of Appendix 6J, accurate up to two decimal points. 1.1.302 *TPC Price Parameter* refers to a value as determined by the *Authority*, which is used for the calculation of the *temporary price cap* in accordance with section J.1.7A of Appendix 6J 1.1.303 *TPC Primary Reserve Multiplier* refers to the multiplier used in the calculation of ResPriPriceMax in accordance with section J.1.7A. The multiplier is to ensure the ratio between	

Existing Market Rules	**Proposed Changes** (Deletions represented by strikethrough text and additions represented by double-underlined text)	Remarks
	EnergyPriceMax and ResPriPriceMax remains consistent between sections J.1.7 and J.1.7A of Appendix 6J, accurate up to two decimal points. 1.1.304 *TPC Regulation Multiplier* refers to the multiplier used in the calculation of RegPriceMax in accordance with section J.1.7A. The multiplier is to ensure the ratio between EnergyPriceMax and RegPriceMax in section J.1.7A of Appendix 6 J remains consistent with that in section J.1.7 of Appendix 6J, accurate up to two decimal points. 1.1.305 *TPC Trigger Period* refers to a number of the most recent block of *dispatch periods* as determined by the *Authority* to be used in the calculation of the *moving average price* under section N.2.1 of Appendix 6N.	