INTERMITTENCY PRICING MECHANISM FOR INTERMITTENT GENERATION SOURCES IN THE NATIONAL ELECTRICITY MARKET OF SINGAPORE

CONSULTATION PAPER

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1. Executive Summary

1.1 Intermittent Generation Sources ("IGS") typically comprise renewable energy generation such as solar and wind energy, where the power output fluctuates, depending on the weather and environmental factors. Based on current technologies, solar generation offers the greatest potential for deployment in Singapore. Solar energy brings about multiple benefits to Singapore, as it generates no carbon emissions and requires no fuel imports.

1.2 Recognising the potential benefits from deploying such technologies, the Government has also announced plans to raise the adoption of solar power in our system to 1 GWp beyond 2020. To support this, the Energy Market Authority ("EMA") has progressively made several regulatory enhancements to facilitate their deployment in Singapore, so that renewables can play a bigger role in our energy mix. These include:

1.2.1 Streamlining market participation and settlement rules to make it easier for IGS to receive payments for excess electricity exported into the grid, including the launch of the Central Intermediary Scheme ("CIS")[1];

1.2.2 Streamlining the commissioning procedures for solar photovoltaic (PV) installations to connect to the grid;

1.2.3 Launching the one-stop solar PV portal which allows consumers to access information easily on the regulatory framework; and

1.2.4 Reviewing metering requirements to allow eligible consumers to use an alternative arrangement (such as an estimated IGS profile that is approved by the EMA) for the settlement of relevant market charges, thereby lowering the metering costs for such consumers.

1.3 IGS such as solar installations have positive and negative externalities because of the inherent characteristics of their output. On the positive side, energy produced from solar resources reduces our reliance on fuel imports and does not generate carbon emissions, which will contribute towards meeting Singapore's overall climate change objectives. The Government has announced plans to implement a carbon tax from 2019. This will give renewable sources like solar a tax advantage compared to fossil fuels, and strengthen the price signal to encourage greater deployment of renewables.

1.4 However, IGS such as solar also have negative externalities. The amount of electricity generated from solar panels is largely dependent on environmental factors

[1] The scheme allows contestable consumers with solar system less than 1 MWac to receive payment, through SP Services ("SPS"), for selling excess solar electricity back to the grid.

and weather conditions, such as the amount of irradiance, cloud cover and shadows. For example, a moving cloud can cause a sudden drop in the amount of electricity produced by the solar panel over a short period. Although individual IGS installations tend to be small by nature, on an aggregate basis, they can impose a significant burden on the power system due to their intermittent nature. Hence, reserves (or back-up capacity) would need to be procured from standby generators to correct such disruptions in electricity production, and ensure power system security and reliability for consumers.

1.5 To ensure the sustainable growth of IGS, a balance has to be struck between the benefits of IGS and intermittency costs it imposes on the system. Hence, it is appropriate to consider a mechanism to allocate the fair share of reserves costs to IGS (henceforth referred to as the Intermittency Pricing Mechanism ("IPM"))[2] in tandem with carbon tax.

1.6 This paper articulates the proposed allocation method of reserves costs through the IPM to better recognise the characteristics and effects of IGS on the power system, particularly in anticipation of the growth of IGS capacity in Singapore. The IPM will determine the reserves cost based on all possible instances of complete or partial electricity supply reduction from all types of generation, to ensure that the cost of reserves is allocated fairly to all generation types that contribute to the need for reserves, including IGS.

1.7 Under the IPM, the estimated output of the IGS installations connected to the grid could be aggregated as a single IGS unit to account for the risk imposed by geographically spread IGS installations as a whole, so that the appropriate quantity of reserves can be scheduled to safeguard the security and reliability of the power system. Based on the historical solar irradiance data across the whole of Singapore, the aggregated IGS unit will not suffer from total unexpected generation loss (unlike a conventional generator when it trips). However, it will still experience significant reductions in output more frequently than a conventional generator would.

1.8 The IPM will take into account the frequency and magnitude of any loss in output occurring for all generation units in each half-hour period, and distribute the reserves costs accordingly.

1.9 With respect to the implementation timing of the IPM, the EMA had previously indicated that the IPM will be implemented when 600 MWac of solar installations have been installed in the system. <u>Given the recent announcement on carbon tax, the EMA is reviewing the implementation timing of the IPM, taking into account factors such as the timing for the implementation of the carbon tax, and the level of IGS capacity in the system</u>. The EMA will inform the industry ahead of the IPM's implementation.

[2] The EMA has previously indicated in the Final Determination Paper "Enhancements to the Regulatory Framework for Intermittent Generation Sources in the National Electricity Market of Singapore" (1 Jul 2014) that we are studying the reserves charging mechanism to better take into account the intermittent nature of IGS.

2. Intermittency Pricing Mechanism

2.1 Current Reserves Charging Framework

2.1.1 Generating units participating in the National Electricity Market of Singapore ("NEMS") are subject to reserves charges. Reserves, or back-up capacity, are required to ensure the reliable supply of electricity to consumers and the secure operation of the power system. There are two broad categories of reserves in the NEMS: regulation reserves and spinning reserves. The EMA determines the half-hourly quantities of regulation reserves to cater for load and generation output variation. Spinning reserves is determined based on the expected size of possible contingency events, currently based on the output of the largest online generating unit scheduled in each dispatch period. The reserves are procured through the electricity market, where prices are determined on a half-hourly basis. The costs of the reserves are subsequently allocated to the relevant stakeholders, broadly based on the "causer-pays" principle where participants pay their share of the costs they impose on the system (see Annex 1 for details).

2.2 Implementation of the Intermittency Pricing Mechanism

2.2.1 Under the IPM, individual IGS installations could be aggregated as a single IGS generating unit[3]. The amount of reserves required to provide back-up for the IGS generating unit will be based on the potential loss of IGS power due to weather conditions or other contingency events. The cost will then be allocated to the IGS generating unit, together with the other conventional generating units, based on the existing reserves charging framework. The cost allocated to the IGS generating unit will be shared among the individual IGS installations based on their respective installed capacity.

2.2.2 Upon its implementation, the IPM will apply to all IGS, except for certain groups which the EMA had previously indicated that would not be subject to the IPM. The groups include:

a. residential consumers[4] with embedded IGS[5] installations; and

b. non-residential consumers with embedded IGS installations connected to the system on or before 31 January 2018[6], unless (i)

[3] Only grid connected IGS installations, subject to the IPM, will be aggregated under this IGS generating unit. Refer to para 2.2.2 for more details.

[4] This group refers to consumers with a residential load account according to the Market Support Services Licensee ("MSSL") (i.e. SPS).

[5] The EMA has released a determination paper, that residential consumers, regardless of contestability status, will pay regulation reserves charges (i.e. Allocated Regulation Price, "AFP") on a net basis if they have an embedded IGS installation of less than 1 MWac. Refer to https://www.ema.gov.sg/cmsmedia/Consultations/Electricity/Determination%20paper%202017%20-%20Enhancements%20to%20the%20regulatory%20framework%20vf.pdf for further information.

[6] As highlighted in the Clarification Paper published on 24 February 2015, non-residential consumers with embedded IGS who have a commissioning date for their IGS 6 months after the date of the release of EMA's next consultation or determination paper on the pricing mechanism, will be subject to the new pricing mechanism.

they retrofit their IGS systems such that re-commissioning by SP PowerGrid would be required in the process; or (ii) 25 years from the commissioning date of their existing IGS systems, whichever occurs earlier.

2.2.3 Specifically, the IPM will only apply to non-residential consumers with embedded IGS (both contestable and non-contestable) and generators[7], as such consumers and generators are in a better position to manage the commercial risks of the investments. Nonetheless, existing non-residential consumers who are early adopters of the technology and have already made investments in intermittent generation technologies before the implementation of the IPM will be "grandfathered", and not be subject to the IPM (subject to para 2.2.2b).

2.3 Methodology for the Intermittency Pricing Mechanism

2.3.1 The IPM comprises the following key parameters: (i) Estimated Maximum Power Reduction ("EMPR") from the aggregated IGS generating unit; and (ii) Expected % Output Reduction Rate ("EORR") of the aggregated IGS generating unit, relative to other conventional generating units. This section sets out the proposed methodology for setting these parameters.

2.3.2 Estimated Maximum Power Reduction ("EMPR")

2.3.2.1 Conventional generating units and the aggregated IGS generating unit differ in their characteristics. While the maximum loss of power output of a conventional generating unit is equivalent to its scheduled energy quantity, the maximum loss for the aggregated IGS generating unit will vary across dispatch periods due to changes in solar irradiance at different times of the day, and changes in the aggregated IGS generating unit size.

2.3.2.2 The EMA proposes for the EMPR of the aggregated IGS generating unit to be derived using historical estimates[8] of the maximum reduction in the PV output observed for that dispatch period.

2.3.3 Expected % Output Reduction Rate ("EORR")

2.3.3.1 The Probability of Failure ("PoF") refers to the probability of a forced outage occurring within a settlement interval. In the Market Rules Chapter 7 Appendix 7A for the Calculation of the Reserve Responsibility Shares, the Energy Market Company ("EMC") shall, in consultation with the Power System Operator ("PSO"), establish procedures for determining and updating from time to time, but not for each settlement interval, the PoF of each Generation Registered Facility ("GRF") based on the operating experience with that GRF and similar GRFs.

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[7] Refers to IGS generation installed to inject all electricity generated into the grid (e.g. solar farm).

[8] The estimate will be based on the historical measured solar irradiance of the IGS generating unit's power output between the 1st and 30th minute of the same dispatch period and it will be scaled according to the IGS generating unit size.

2.3.3.2 Based on the historical solar irradiance data, the aggregated IGS generating unit will not suffer from a total unexpected loss of power output (unlike a conventional generating unit when it trips). The geographical spread of IGS installations means that the intermittency of the aggregated IGS generating unit over a period of time would be less pronounced than the intermittency of any individual IGS generating unit.

2.3.3.3 In addition, under Chapter 8 of the Market Rules, a forced outage means an unanticipated intentional or automatic removal from service of equipment **or the temporary de-rating of, restriction of use or reduction in performance of equipment**.

2.3.3.4 In order to account for all possible instances (complete[9] or partial output reduction) of forced outages, the EMA proposes for the PoF to be revised as the EORR shown below, which will be applied to all generating units, including aggregated IGS and conventional GRFs:

$$\boldsymbol{Expected}\ \%\ \boldsymbol{Output\ Reduction\ Rate}\ (\boldsymbol{where\ Output\ Reduction} > \mathbf{10}\boldsymbol{MW})$$

$$= \left[\sum_{\boldsymbol{i=1}}^{\boldsymbol{C}} \%\ \text{Output Reduction}_i\right] \Big/ \boldsymbol{C}$$

where,

- C refers to the total number of online periods

For IGS:-

- % Output Reduction of period i for the aggregated IGS generating unit refers to:

$$\frac{\boldsymbol{Max}\ [(\boldsymbol{Est.IGS\ Unit\ Output}_{\mathbf{1st\ min}} - \boldsymbol{Est.IGS\ Unit\ Output}_{\mathbf{30th\ min}} - \mathbf{10}),\ \ \mathbf{0}]}{\boldsymbol{Est.IGS\ Output}_{\mathbf{1st\ min}}} \text{ x } 100\%$$

For conventional GRF:-

- % Output Reduction of period i for a conventional GRF refers to:

$$\frac{\boldsymbol{Max}\ [(\boldsymbol{Scheduled\ Output} - \boldsymbol{Actual\ Output} - \mathbf{10}),\ \ \mathbf{0}]}{\boldsymbol{Scheduled\ Output}} \times 100\%$$

- Actual Output for a conventional GRF refers to its output at the end of the half-hour dispatch period.

- IGS and GRF Outputs are in MWac.

[9] Complete output reduction of a GRF refers to occurrences when a conventional GRF trips.

- An online period for the aggregated IGS refers to a period where the aggregated IGS unit is producing power, typically from 7am to 7pm daily.

- An online period for conventional GRFs refers to a period with positive metered Injected Energy Quantities ("IEQ").

2.3.3.5 The EORR will be computed quarterly based on data gathered over a moving one-year window, similar to the current PoF calculation.

2.3.4 Worked examples to illustrate the estimated costs allocated to IGS under the proposed IPM methodology can be found in Annex 2.

2.3.5 Based on the current reserves price and the grid emissions factor, it is estimated that there will be <u>net positive savings for IGS after the implementation of carbon tax and the IPM</u>[10]. More details can be found in Annex 3.

2.3.6 The EMA will continuously monitor developments in the industry and the corresponding impact on the grid[11]. The EMA will also review the parameters over time, to take into account potential changes such as improved solar forecasting, the entry of other IGS technologies (such as wind and tidal), and the deployment of more technologies (such as energy storage) which can address the intermittency issue of IGS.

2.3.7 If an energy storage solution is integrated with an IGS, it may reduce the intermittency of output and hence the burden to the system. However, as such installations are still few, they will be treated the same as a typical IGS installation. The EMA will review whether IGS with energy storage could be treated as separate from the IGS generating unit and allocated a lower EORR, potentially lowering the cost of reserves for these installations. This will incentivise IGS installations to come up with solutions to proactively manage their intermittency.

[10] Based on the estimated reserves costs stated in Annex 2 Table 4.

[11] The Final Determination Paper published on 1 July 2014 highlighted that there may be localised limits at specific geographical regions. IGS investors should check with the EMA and SP PowerGrid ("SPPG").

3. Next Steps

3.1 The EMA seeks views on the proposed methodology for the IPM identified in this consultation paper. This includes the following:

3.3.1 the overall framework of the IPM based on the principle of aggregating individual IGS installations as a single IGS generating unit in determining the reserves share allocated to IGS;

3.3.2 the EMPR of the aggregated IGS generating unit for IGS; and

3.3.3 the EORR methodology to be applied to all generating units, including aggregated IGS and conventional GRFs.

REQUEST FOR COMMENTS AND FEEDBACK

The EMA invites comments and feedback to the consultation paper.

Please submit written feedback to goh_chia_jin@ema.gov.sg, lyana_yeow@ema.gov.sg and ren_kejia@ema.gov.sg by 31 October 2017. Alternatively, you may send the feedback by post/fax to:

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Anonymous submissions will not be considered.

The EMA will acknowledge receipt of all submissions electronically. Please contact Mr Goh Chia Jin at 6872 7369, Ms Lyana Yeow at 6376 7624 or Ms Ren Kejia at 6376 7759 if you have not received an acknowledgement of your submission within two business days.

The EMA can facilitate meetings with stakeholders on an individual basis to discuss their feedback to this consultation paper. Please contact the EMA via goh_chia_jin@ema.gov.sg, lyana_yeow@ema.gov.sg and ren_kejia@ema.gov.sg if you wish to arrange a meeting.

The EMA reserves the right to make public all or parts of any written submissions made in response to this consultation paper and to disclose the identity of the source. Any part of the submission, which is considered by respondents to be confidential, should be clearly marked and placed as an annex which the EMA will take into account regarding the disclosure of the information submitted.

ANNEX 1: Existing Reserve Charging Framework in the NEMS

1. Generating units participating in the NEMS are subject to reserve charges. Reserves, or back-up capacity, are required to ensure the reliable supply of electricity to consumers and the secure operation of the power system. There are two broad categories of reserves in the NEMS: regulation and spinning reserves.

    a. **Regulation Reserve.** Regulation reserve refers to the amount of generation capacity needed to balance the minute-to-minute variations in electricity consumption of all loads and small variations in generating units' output. The cost of regulation reserve is recovered from all loads and the first 5 MWh of each generation facility in each half hour period, on the basis that it is due to the fluctuations in loads and small variations in generation output that create the need for regulation reserve in the first place.

    b. **Spinning Reserve.** Spinning reserve is necessary to maintain reliability of supply. It refers to the amount of generation capacity required to correct large imbalances in the system due to significant reduction in generating units' output. The cost of spinning reserve[12] is recovered from all generation facilities scheduled (less the first 5 MWh of each facility, which is allocated the cost of regulation reserve) operating in that half-hour through a methodology that varies according to the scheduled/forecasted generation output based on the Modified Runway Model.

2. The reserves are procured through the NEMS, where prices are determined on a half-hourly basis. The costs of the reserves are subsequently allocated to the relevant stakeholders, viz loads and generation facilities based on the "causer-pays" principle where participants pay their share of the costs they impose on the system. A summary of the existing reserve cost allocation framework for generation facilities is shown in Table 1 below.

Table 1: Existing reserve cost allocation framework for generation facilities

Scheduled Output	Regulation Reserve Cost	Spinning Reserve Cost
5 MWh and below (10 MW and below for a half-hourly period)	√	x
Above 5 MWh (Above 10 MW for a half-hourly period)	√ (for first 5 MWh)	√ (for > 5 MWh)

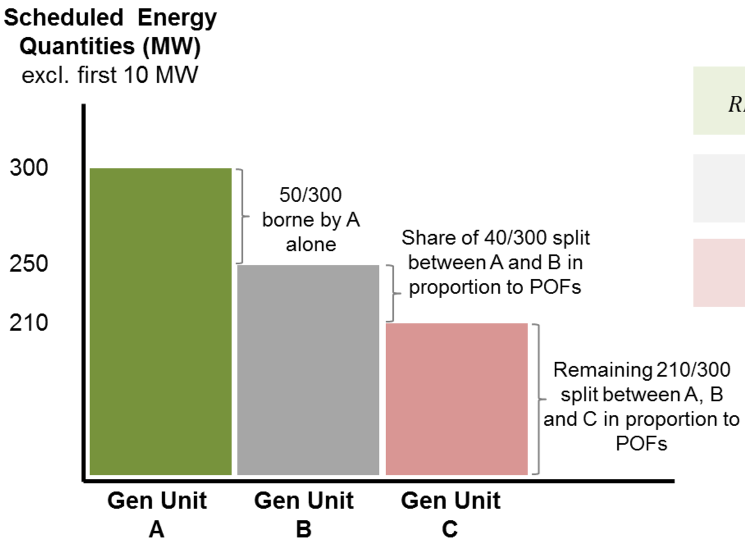
3. **Modified Runway Model.** The cost to procure spinning reserves is allocated to generation facilities based off the Modified Runway Model, where higher costs would be

[12] It will be based on the reserve share allocated, where a PoF would be assigned to the aggregated IGS generating unit, as per the current procedures for other generating units in the NEMS.

attributed to: (i) generation units with higher scheduled capacities; and (ii) units with lower reliability. The less reliable a generation unit is, the higher its assigned PoF.

4. Each generation unit's share of the cost, or its Reserve Responsibility Share ("RRS"), is therefore determined by its scheduled capacity for that particular trading period, and its reliability (i.e. PoF). Currently, the PoF for each generation unit is calculated by dividing the number of times the unit trips by the number of half-hour periods the unit is online. The PoF is calculated every three months based on data gathered over a moving one-year window. An illustration of the Modified Runway Model can be found in Figure 2 below.

Figure 2: Illustration of Modified Runway Model



$$RRS_A = \frac{50}{300} + 0.5 * \frac{40}{300} + 0.33 * \frac{210}{300}$$

$$RRS_B = 0.5 * \frac{40}{300} + 0.33 * \frac{210}{300}$$

$$RRS_C = 0.33 * \frac{210}{300}$$

* Assumes equal PoFs for the 3 generating units.

ANNEX 2: Worked Examples to Illustrate Estimated Costs Allocated to IGS under IPM

1. For illustration purpose, the cost estimates for IGS under IPM are developed based on the assumptions in Table 3 below, and using historical costs for regulation and spinning reserves. The actualised costs under IPM are subject to the prevailing market conditions and future advancements in areas such as energy storage systems.

Table 3: Key assumptions for cost estimate inputs

Parameter	Assumption
IGS capacity that is not subject to the IPM	200 MWac
EMPR of the aggregated IGS generating unit	Estimated based on the maximum observed half-hourly reduction using historical solar irradiance figures[13] and the capacity of the IGS generating unit.
EORR	EORR of the aggregated IGS generating unit is 7.65%
Cost of regulation reserves	$0.15 per MWh of load[14]
Cost of spinning reserves	$3,400 per half-hour in total[15]

2. For each half-hour period, the total spinning reserve cost will be allocated to the aggregated IGS generating unit under the Modified Runway Model as illustrated in Figure 2. Specifically, the EMPR of the aggregated IGS generating unit will be used to determine its RRS relative to conventional generating units for output above 10 MW, taking into account their respective EORR.

[13] Estimated based on the 2016 solar irradiance data from the Solar Energy Research Institute of Singapore ("SERIS").
[14] Based on average AFP in 2016.
[15] Based on average total spinning reserve costs from 2012 to 2016.

3. Based on the assumptions set out in Table 3, the estimated monthly regulation and spinning reserve costs under the proposed IPM is shown in Table 4 for various levels of IGS capacity installed. The total cost of the regulation reserve charge and the spinning reserve charge is then allocated to all IGS subject to the IPM, prorated based on their individual installed capacity.

Table 4: Monthly reserve cost estimates per MWh of IGS generation

Parameters	**Total IGS Capacity Installed**		
	600 MWac	**1,000 MWac**	**1,200 MWac**
Regulation reserve cost ($/MWh)	0.005	0.003	0.002
Spinning reserve cost ($/MWh)	3.42	3.50	3.55
Total reserves cost (i.e. regulation reserve and spinning reserve costs) ($/MWh)	3.43	3.50	3.56
Total reserves cost as % of avoided retail price[16]	2.2%	2.3%	2.3%
Total reserves cost as % of solar PV capital cost[17]	2.7%	2.7%	2.8%

[16] It refers to the amount of savings IGS consumers receive from consuming solar electricity from their embedded solar PV generation instead of buying electricity from their retailers. The retail price is based on the average retail price from 2014 to 2016.

[17] Based on the assessment of future solar PV system costs stated in the SERIS's 2013 Solar PV Roadmap for Singapore of 0.9 USD/Wp. In addition, a 5% interest p.a. over 20 years was included in the estimation.

ANNEX 3: Worked Examples to Illustrate Comparison of Avoided Carbon Tax and Reserves Cost Borne by IGS under the IPM

Table 5: Comparison of avoided carbon tax vis-a-vis the reserves costs borne by IGS under the IPM

Parameters	**Level of IGS deployment**		
	600 MWac	**1,000 MWac**	**1,200 MWac**
[1] CO_2 avoided (tCO_2/MWh)[18]	0.4244		
Avoided carbon tax ($/MWh) = [1] x potential carbon tax range of $10 to $20 per tCO_2 (as announced at Budget 2017)	4.24 to 8.49		
Reserves costs borne by IGS under IPM ($/MWh)	3.43	3.50	3.56

[18] Based on 2016 Grid Emission Factor of 0.4244 tCO_2/MWh.