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

FINAL DETERMINATION PAPER

30 October 2018

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

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 photovoltaic (PV) offers the greatest potential for deployment in Singapore. Solar PV brings about multiple benefits, as it generates zero carbon emissions and requires no fuel imports. This will contribute towards meeting Singapore's overall climate change goals. Recognising these benefits, the Government plans to raise the adoption of solar power to 350 MWp in 2020 and to 1 GWp beyond 2020.

1.2. The Energy Market Authority ("EMA") supports greater solar growth in Singapore, while also keeping to our core principle of pricing energy right to ensure fair and sustainable growth with long term benefits to consumers. To this end, the EMA has been making several regulatory enhancements to facilitate the entry of solar into the electricity market of Singapore. These include streamlining regulations and reducing compliance costs, such as through the implementation of the Enhanced Central Intermediary Scheme ("ECIS") and the use of Solar Generation Profile.

1.3. The EMA also recognises the intermittent nature of IGS, which can affect the stability of our electricity system. The amount of electricity produced by IGS is affected by weather conditions, which can cause a sudden drop in the amount of electricity generated over a short period. There can be potential disruptions to electricity supply if such drops are not carefully managed. Hence, reserves (or back-up capacity) have to be procured from standby generators to balance such intermittency to ensure power system reliability for consumers.

1.4. The EMA thus launched a public consultation on 1 August 2017 on the proposed Intermittency Pricing Mechanism ("IPM") to recognise the characteristics and effects of IGS on the power system and reduce cross subsidisation across stakeholders. This will better allocate the fair share of reserves cost to all generation types that contribute to the need for reserves. After careful consideration of the feedback received, the EMA will provide more details and clarity on the IPM parameters, and give suggestions on how IGS players can potentially manage their reserves cost. The IPM is projected to be implemented around 2020, after the relevant market rules and IT systems have been changed.

1.5. The IPM will promote the price signal which will encourage the industry to invest in measures to manage IGS intermittency. Such solutions can include energy storage systems ("ESS") and demand-side management ("DSM"), which have potential benefits for both consumers and the power system, and enable higher levels of solar adoption in Singapore. The EMA will roll out supporting initiatives to spur such opportunities for the industry and catalyse new business models. The EMA will also continually review the IPM framework to ensure it remains relevant and updated amidst changing technologies and levels of IGS deployment.

2. Background

2.1 The EMA recognises the benefits of renewable IGS and has made several regulatory enhancements to support their growth and facilitate their entry into the electricity market. These include:

2.1.1 Allowing smaller contestable consumers ("CCs") with embedded generators with installed capacity of less than 10 MW to sell electricity through a central agent (i.e. SP Services) under the ECIS, without the need for market registration[1];

2.1.2 For CCs with IGS with installed capacity of less than 10 MWac who generate power for self-consumption, the EMA has created a new fit-for-purpose Market Participant ("MP") class (i.e. IGS non-exporting MP class) to remove unnecessary MP requirements;

2.1.3 Providing CCs with embedded IGS the choice of using the Solar Generation Profile[2], or continuing to install physical meters for the purpose of paying applicable market-related charges;

2.1.4 Lowering barrier of entry for small generators by reviewing the structure of generation licence fees. A tiered fixed fee of $148/MW was introduced for generators between 10 MW to 400 MW, which reduces the previously step-jump increase of $100 to $58,000 in the fixed fee component when the size of the generator goes beyond 10 MW;

2.1.5 Reducing the regulatory burden for small solar PV systems with installed capacity below 1 MWac by removing the requirement to submit real-time AC power output measurements at one minute intervals to the Power System Operator ("PSO"); and;

2.2 The EMA has also worked with government agencies and stakeholders to roll out supporting initiatives to promote the deployment of solar:

2.2.1 Awarded the Energy Storage Grant Call in June 2016 to develop cost-effective energy storage solutions that can be effectively deployed in Singapore;

2.2.2 Awarded the solar forecasting grant call in October 2017 to develop a multi-timescale solar forecasting solution that will enable better management of intermittency from solar generation;

2.2.3 Awarded the EMA-SP ESS test-bed in October 2017 to implement Singapore's first utility scale ESS to better understand the feasibility of

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[1] More information on market registration schemes for solar PV consumers is available at https://www.ema.gov.sg/Guide_to_Solar_PV.aspx

[2] More information is available at https://www.ema.gov.sg/Solar_Generation_Profile.aspx

deploying grid-level energy storage technologies in Singapore's hot and humid environment;

2.2.4 Formed a Technical Standards Working Group under Enterprise Singapore (ESG)'s Singapore Standardisation Programme to track and monitor international standards in ESS (e.g. fire safety and communications/control protocols), and to establish local technical guidelines for ESS deployment in Singapore based on industry and government needs;

2.2.5 Co-launched a joint grant call with ESG in September 2018 for local enterprises to develop innovative and cost-effective solutions to mitigate solar intermittency[3];

2.2.6 Published the ESS Policy Paper in October 2018 to provide clarity on the regulatory framework to facilitate entry of ESS into our electricity market.

2.3 IGS are also intermittent in nature, and can affect system stability. For example, cloud cover can cause a sudden drop in the amount of electricity generated by a solar PV system over a short period. There can be potential disruptions to electricity supply if such drops are not carefully managed. Hence, reserves (or back-up capacity) would need to be procured from standby generators to correct such drops, and ensure power system reliability for consumers.

2.4 To ensure the sustainable growth of IGS, it is necessary to recognise the characteristics and effects of IGS on the power system. Hence, EMA had earlier launched a consultation on 1 August 2017 on the proposed mechanism (i.e. Intermittency Pricing Mechanism ("IPM")) to allocate the fair share of reserves costs to IGS and better recognise the characteristics and effects of IGS on the power system.

Recap of the 2017 Consultation Paper

2.5 To recap, the IPM enhances the existing Modified Runway Model to allocate the costs of spinning reserves to IGS as well as conventional generation facilities. The IPM will determine the share of spinning reserves allocated to generators based on all possible instances of complete or partial electricity supply reduction from all types of generation sources (including IGS), to ensure that the cost of reserves is allocated fairly to all generation types that contribute to the need for reserves. Although individual IGS installations tend to be small, on an aggregate basis, they can impose a significant burden on the power system due to the correlation across the different installations, and their intermittency. Hence under IPM, individual IGS installations will be aggregated as a single unit to account for the collective burden they impose.

2.6 Under the Modified Runway Model, higher spinning reserve costs are attributed to: (i) generation units with higher scheduled capacities; and (ii) units with lower

[3] More information is available at
https://www.ema.gov.sg/media_release.aspx?news_sid=20180919ygPkGNjxyt64

reliability. Each generating unit's share of total spinning reserve costs or its Reserve Responsibility Share ("RRS") will be determined by the following key parameters (refer to <u>Figure 1</u> for illustration):

2.6.1 Estimated Maximum Power Reduction ("EMPR") (i.e. quantum of power loss)

2.6.1.1 The EMPR of a conventional generating unit is equivalent to its scheduled energy quantity; and

2.6.1.2 The EMPR of the aggregated IGS generating unit is derived using historical estimates[4] of the maximum reduction in the output observed for that dispatch period from the aggregated IGS generating unit; and

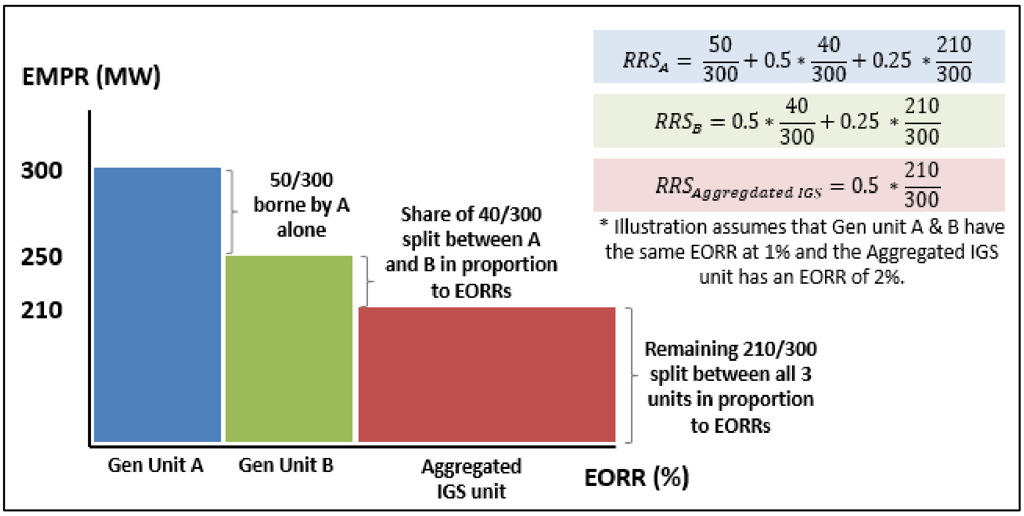
2.6.2 Expected % Output Reduction Rate ("EORR") (i.e. probability of power loss)

2.6.2.1 The Probability of Failure ("POF") to be revised to EORR to account for all possible instances (complete[5] or partial output reduction) of forced outages.

2.6.2.2 The EORR will be applied to all generating units, including the aggregated IGS unit and conventional Generation Registered Facilities ("GRFs").

2.6.3 The cost allocated to the aggregated IGS generating unit will be shared among the individual IGS installations based on their respective installed capacity[6].

Figure 1: Illustration of the Modified Runway Model under IPM



[4] Refer to Annex 2 for the detailed derivations

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

[6] If the aggregated IGS generating unit is coupled with ESS and is not fully dispatchable, the reserves cost will be allocated based on the individual IGS generating unit's EMPR (refer to Annex 4).

2.7 The IPM will apply to all IGS installations, except for certain groups which the EMA has previously indicated in the consultation paper that would not be subject to the IPM. These groups include:

2.7.1 Residential consumers with embedded IGS installations; and

2.7.2 Non-residential consumers with embedded IGS installations connected to the system on or before 31 January 2018, unless (i) 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.

2.8 Specifically, the IPM will only apply to non-residential consumers with embedded IGS (both contestable and non-contestable) and generators, 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 deadline given in the previous consultation paper on the IPM will be "grandfathered", and not be subject to the IPM (subject to para 2.7).

2.9 Following the close of consultation on 31 October 2017, the EMA received feedback from 13 stakeholders. Table 1 shows the list of industry stakeholders who provided feedback to the consultation paper. Out of the 13, 1 chose to remain confidential.

Table 1: List of stakeholders

Solar Companies	Market Operator/ Generation Licensee/Transmission Licensee	Research Institute
• Energetix Pte Ltd • Sembcorp Solar • Sunseap Group	• Energy Market Company • Keppel Merlimau Cogen • PacificLight Power • Senoko Energy • Sembcorp Cogen • SP Group • Tuas Power • YTL Power Seraya	• Solar Energy Research Institute of Singapore (SERIS)

2.10 Section 3 of this Final Determination Paper provides the summary of feedback received from the consultation.

3. Summary of Feedback

3.1. The following were key feedback received from the consultation on the proposed implementation of IPM:

3.1.1. There was mixed feedback from the industry on projects to be grandfathered from the IPM. Solar players suggested for EMA to include projects that were committed prior to the launch of the 2017 consultation paper for exemption, while the conventional generation companies ("gencos") felt that there should not be any form of grandfathering to ensure a level playing field.

3.1.2. Industry suggested alternatives or felt that there were shortcomings to aggregate all IGS installations as a single unit for the allocation of reserves costs under IPM. They felt that it did not (i) incentivise individual IGS units to be stable or (ii) encourage localised solutions that can help smoothen variability onsite. One stakeholder also queried if there was a need to have separate treatment for larger IGS which can concentrate intermittency at a single location.

3.1.3. Industry sought greater clarity on the EMPR methodology, specifically on:

3.1.3.1. What was the rationale for it to be based on the difference between the output for 1st and 30th minute;

3.1.3.2. How it would be derived based on the historical irradiance;

3.1.3.3. Whether it would be based on the gross or net output of IGS;

3.1.3.4. How often the EMPR would be updated. Industry also requested for the formula and figures to be published for greater transparency.

3.1.4. Industry also sought clarity and provided suggestions on the percentage output reduction used in the calculation of the EORR, specifically on:

3.1.4.1. The use of actual output of the IGS unit or deviation from forecasted output of IGS to determine the applicable reserves cost;

3.1.4.2. Analysis on how the aggregated IGS unit will not suffer from total unexpected loss of power output and why the intermittency of an aggregated IGS unit might be less pronounced than an individual IGS unit;

3.1.4.3. How often the EORR will be updated. Industry also requested for the formula and figures to be published for greater transparency.

3.1.5. Industry was supportive of the principles behind the IPM. However, solar players were concerned that it may stifle the growth of IGS or felt that it was unclear on the necessity to implement it for IGS systems installed and connected as early as 31 January 2018. Some had commented that EMA was bringing forward the implementation of reserves charging as EMA had earlier in July 2014 indicated that existing reserves could support 600 MWac of IGS.

3.1.6. Solar players also raised concerns over the reserves cost levied under the IPM relative to the avoided carbon tax. They opined that there might not always be net benefit to IGS as the avoided carbon tax may not outweigh the potential costs faced under IPM. They were concerned that the cost accrued to IGS could escalate with its increased aggregate adoption, while improvements in generation efficiency could result in lower carbon tax on conventional generation. Thus, they suggested that EMA could instead adopt a “wait-and-see” approach taking into consideration (i) the outcomes of ongoing projects such as Solar Forecasting and ESS and (ii) the effect on market competition and (iii) the uptake of renewable energy projects post-carbon tax implementation.

3.1.7. Industry also noted that reserve prices fluctuate and might grow when IPM is implemented or in the future. This could create uncertainty and delay the adoption of IGS. A few stakeholders were concerned that consumers with IGS would face greater risks and uncertain costs as compared to conventional generators as they currently had limited abilities to provide spinning reserves, while conventional generators could better balance the costs of reserves.

3.1.8. Conventional generators raised concerns that they would be double penalised under the Automatic Financial Penalty Scheme (“AFPS”) and the IPM if the EORR accounts for partial outages.

3.1.9. Some stakeholders also enquired on the IPM framework’s treatment of ESS and other solutions that could mitigate intermittency.

4. EMA's Final Determination

4.1. **Key Principles behind the IPM**

The EMA would like to highlight that the IPM is based on the following key principles:

4.1.1. Causer-pays principle where all generating units, whether IGS or conventional generators, pay for their fair share of reserves cost as they require backup from the system. Similar causer-pays approaches are adopted in other jurisdictions (such as Australia, Spain, Denmark and California)[7] where costs allocated amongst conventional generators and IGS are based on their contribution to intermittency.

4.1.2. Fair allocation of costs where the IPM will reduce the cross-subsidisation borne by conventional generators as they are currently bearing the full costs of reserves and paying for IGS' share of reserves.

4.1.3. Promote the price signal to encourage industry to invest in solutions to manage intermittency and keep their reserves cost manageable.

4.1.4. Encourage the adoption of various solutions to mitigate intermittency as EMA is solution-agnostic. Some examples of possible solutions include ESS and demand side management.

4.1.5. Utilise a data-driven approach to determine the parameters for the calculation of reserves cost under IPM.

4.2. **Groups that will be subjected to the IPM**

After careful consideration, the IPM will apply to all IGS (regardless of whether they are selling electricity back to the grid), except for certain groups which the EMA had previously indicated that would not be subject to the IPM. These groups include:

4.2.1. Residential consumers[8] with embedded IGS[9] installations; and

4.2.2. Non-residential consumers with embedded IGS installations connected to the system on or before 31 January 2018, unless (i) they retrofit their IGS systems such that re-commissioning by SP PowerGrid would be required

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[7] Please refer to Annex 1 for more information

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

[9] 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.

in the process; or (ii) 25 years have passed from the commissioning date of their existing IGS systems, whichever occurs earlier.

4.2.3. Specifically, the IPM will only apply to non-residential consumers with embedded IGS (both contestable and non-contestable) and generators, as such consumers and generators are in a better position to manage the commercial risks of the investments.

4.2.4. Nonetheless, existing non-residential consumers who are early adopters of the technology and have already made investments in intermittent generation technologies before the deadline given in the 2017 consultation paper on the IPM will be "grandfathered", and not be subjected to the IPM (subject to para 4.2.2).

4.3. Aggregation of IGS to account for collective burden on the system

4.3.1. The EMA notes that the industry has questioned the rationale behind aggregating IGS installations. EMA has studied historical solar irradiance data (in per minute sampling) measured by widely spread solar irradiance sensors across Singapore and found a relatively high level of correlation[10] among the measurements. This means that unlike conventional generating units whose decrease in output occur independently of each other, IGS installations across Singapore tend to decrease in output at the same time. The quantity of reserves procured would need to be able to cover the loss in output of IGS installations located across the island as a whole. Hence, the estimated output of the IGS installations connected to the grid will be aggregated as a single IGS unit to account for the overall impact of IGS installations on the grid.

4.3.2. In addition, only fully intermittent and partially intermittent IGS installations will be aggregated as a single unit as their reliability is expected to be highly correlated with changes in weather conditions. The reserve charges to be attributed to a partially intermittent IGS will be based on its EMPR[11], to reflect that the loss resulting from a partially intermittent IGS is smaller than that of a fully intermittent IGS.

4.3.3. If an IGS paired with solutions is proven to be fully dispatchable[12], it will be treated as a separate unit. (More details on this are indicated in subsequent sections of this paper.) This will encourage individual IGS to consider solutions to smoothen its intermittency.

[10] Correlation, denoted by Coefficient of Determination, R^2 for solar irradiance data (in per minute) measured by widely spread solar irradiance sensors across Singapore, is above 80%.
[11] Refer to Annex 4 for the proposed treatment for a partially intermittent IGS.
[12] As per the market rules, dispatch means the act of receiving an instruction as to the level of a registered facility's physical operation required in a given dispatch period, and operating in accordance with such an instruction.

4.3.4. A technical concern of localised voltage issue, rather than shortfall in reserves, may be potentially faced by a large IGS installation concentrated at a single node. EMA is currently reviewing this matter together with SP PowerGrid to address any potential localised voltage issue.

4.4. Clarification on the EMPR and EORR

4.4.1. To recap, the methodology for IPM comprises two 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. The EMA would like to provide clarity on the EMPR and EORR formula for both the conventional generating units and the aggregated IGS generating unit.

Estimated Maximum Power Reduction (EMPR)

4.4.2. 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.

4.4.3. The EMPR of the aggregated IGS generating unit, which is computed annually, is the estimated maximum power output reduction of the aggregated IGS generating unit observed in a dispatch period. For example, the EMPR for period 24 is:

$$\boldsymbol{EMPR}_{\,\boldsymbol{Period\,24}}\,(\boldsymbol{MWac}) \\ = \boldsymbol{Maximum}\left\{\boldsymbol{Reduction}_{\,\boldsymbol{Day\,1,\ \ Period\,24}}, \boldsymbol{Reduction}_{\,\boldsymbol{Day\,2,\ \ Period\,24\,\ldots}}, \boldsymbol{Reduction}_{\,\boldsymbol{Day\,365,\ \ Period\,24}}\right\}$$

where $Reduction_{\,Day\,i,\,Period\,24}$ refers to the largest reduction in IGS generating unit output observed in a thirty-minutes dispatch period.

4.4.4. The EMPR will then be scaled according to the aggregated IGS generating unit size, on a monthly basis, and applied in the calculation of the Reserve Responsibility Shares ("RRS") and Market Clearing Engine ("MCE") risk calculation formula, similar to the risk calculation formula for a Generation Registered Facility ("GRF"). The detailed derivations are shown in Annex 2.

Expected % Output Reduction Rate (EORR)

4.4.5. The EMA has ascertained that the EORR formula is robust in accounting for all possible instances (complete[13] or partial output reduction) of forced outages of generating units, including aggregated IGS and conventional GRFs, and will maintain the formula as per the consultation paper. For clarity, the detailed derivations are shown in Annex 3.

4.4.6. Specifically regarding the industry's concern that the generating unit may seem to be double penalised under AFPS and EORR, the industry should note that the two schemes are different – the AFPS penalises the generating units which are unable to meet their scheduled output, while EORR allocates the cost of utilising reserves to make up for the loss of energy to ensure system security and reliability.

4.5. Proposed Treatment of ESS or other solutions that can mitigate intermittency under IPM

4.5.1. The EMA encourages solution(s) to mitigate IGS intermittency and is solution-agnostic. IGS with ESS, for example, could potentially be treated as separate from the IGS generating unit and allocated a lower EORR, thereby lowering the cost of reserves for these installations. However, as these technologies are largely nascent at this point in time, the EMA is open to the industry's views on ways to ensure fair allocation of reserves cost to IGS that is coupled with solution(s) that mitigate IGS intermittency. For a start, the EMA has proposed a treatment of ESS or other solutions that mitigate intermittency in Annex 4. We welcome industry's views to Annex 4.

4.6. Estimated Reserves Cost under IPM

4.6.1. The estimated costs faced by IGS under IPM is manageable when compared to the (i) levelised cost of energy for IGS installations, (ii) electricity prices for consumers and (iii) reserve costs faced by conventional generators (refer to Annex 5 for more details). EMA will work with the industry to provide details to assist in their calculation of IPM costs.

4.6.2. In addition, if the IGS undertakes intermittency mitigating solutions (e.g. ESS and DSM), it can reduce the amount of reserves cost it faces. Under IPM, the reserves cost faced by IGS will be lowered if the IGS is paired with other solutions that reduces its intermittency. This is also consistent with the principles of promoting the price signal to incentivise the adoption of ESS and other solutions to mitigate intermittency.

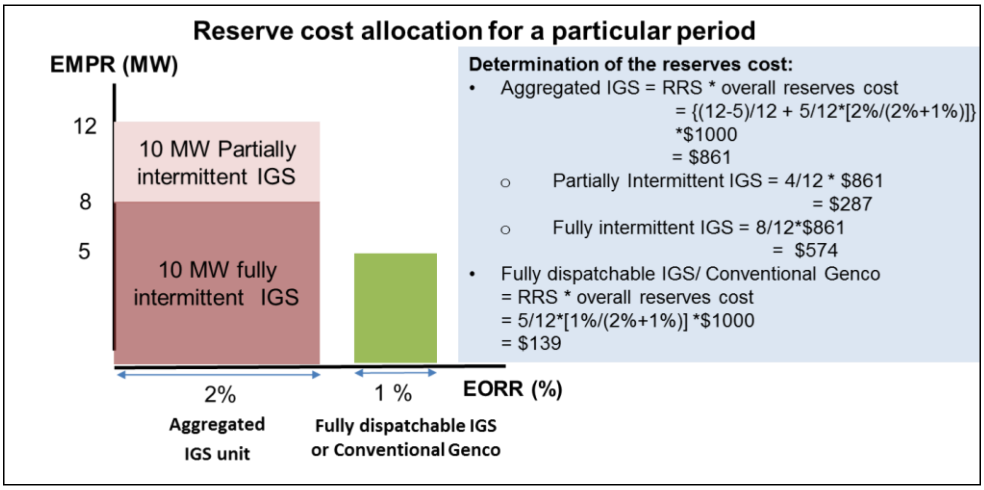
[13] Complete output reduction of a GRF refers to occurrences when a conventional GRF trips.

4.6.3. If an IGS is fully dispatchable[14] after pairing with other solution(s), akin to a conventional generator, it will be treated as a separate individual unit as the probability of failure of such a system is no longer reliant on the weather. The reserves cost charged to the fully dispatchable IGS installation will be based on its own EMPR and EORR, similar to a conventional generator.

4.6.4. If the IGS is not fully dispatchable after it is paired with other solution(s) that reduces its intermittency (i.e. partially intermittent), it will be aggregated with other IGS installations and the reserves cost will be allocated respectively among all IGS units based on the individual installation's EMPR. An individual IGS paired with solutions that has partial intermittency gets a discount based on its EMPR.

4.6.5. Please refer to Figure 2 for an illustrative example of the cost allocation among various units: (i) fully intermittent IGS, (ii) partially intermittent IGS and (iii) fully dispatchable IGS (or a conventional generator).

Figure 2: Illustration of the allocation of reserve costs for the different units[15]



4.6.6. Solutions such as ESS can help to address intermittency and reduce reserves cost by providing grid level frequency regulation or localised ramping to smooth variable output. There have been several case studies in other jurisdictions where this has been applied:

[14] As per the market rules, dispatch means the act of receiving an instruction as to the level of a registered facility's physical operation required in a given dispatch period, and operating in accordance with such an instruction.

[15] Assumptions made for the illustration:

- Overall reserve cost to be allocated in the market is $1000 for a period
- The EMPR of the fully intermittent IGS is 8 MW
- The EMPR of the partially intermittent IGS is 4MW (50% less than a fully intermittent IGS)
- The EMPR of the Fully dispatchable IGS/conventional genco is 5 MW
- The EORR of the Aggregated IGS unit is 2% while the EORR of the fully dispatchable IGS/conventional genco is 1%

4.6.6.1. Notrees Battery Storage Project (Texas, United States)[16]: The 153 MW wind farm is paired with a 36MW/24MWh Li-ion battery storage system to optimise power delivery and provide frequency regulation service in the Electric Reliability Council of Texas (ERCOT) market.

4.6.6.2. PNM Prosperity Energy Storage Project (New Mexico, United States)[17]: The 500kW solar PV installation is co-located with a 500kW battery to smooth variable output and a 250KW/1MWh battery for peak shifting.

4.6.6.3. Hornsdale Power Reserve (Jameston, South Australia)[18]: The 315 MW Hornsdale wind farm is co-located with a 100MW/129MWh battery. It participates in all competitive energy and ancillary services markets and also receives fixed payments to provide critical grid reliability and protection services.

4.7. **Regulation Reserves Cost**

4.7.1. For clarity, the cost of regulation for a particular period will continue to be charged to all loads and up to the first 5 MWh of each conventional generating unit.

4.7.2. The fully and partially intermittent IGS will share the regulation reserve cost allocated to the aggregated IGS unit based on proportion of their individual contribution to the generation of the aggregated IGS unit. (i.e. the proportion of their individual generation as compared to the generation of the aggregated IGS unit).

4.7.3. A fully dispatchable IGS unit will bear its relevant regulation reserves cost on its own, similar to a conventional generator.

4.8. **Reserves Cost**

4.8.1. The EMA notes that there were concerns raised by the industry that (i) IGS have no control over reserves cost as they are determined by bids from conventional generators and (ii) that conventional generators can better manage reserves cost since they can also provide reserves.

4.8.2. The EMA will continue to encourage competition and allow reserves providers to enter the market and exert downward pressure on reserves cost. In the future, IGS paired with other solutions such as ESS can help

[16] Case Studies: Battery Storage, IRENA, 2015
[17] Case Studies: Battery Storage, IRENA, 2015
[18] Lessons from Tesla's World-Beating Battery, Bloomberg New Energy Finance, 2018

to mitigate increases in reserves cost, especially if such solutions become more cost-competitive over time. For example, the Bloomberg New Energy Finance (BNEF) projects that the payback periods for residential solar PV and ESS in Australia will equalise with new CCGTs between 2023 to 2030[19]. Furthermore, IGS when paired with solutions that allows it to participate in the reserves market can similarly balance their reserves cost like any other conventional generator.

4.9. **Implementation of IPM**

4.9.1. The 2017 consultation paper on IPM had indicated that EMA was reviewing the implementation timing of the IPM, taking into account factors such as the timing for the implementation of carbon tax and the level of IGS capacity in the system. The EMA has since considered that implementing the IPM as soon as practicable will send the right price signal for industry to consider and implement their own measures to address intermittency. Hence the IPM is projected to be implemented around 2020, after the relevant market rules and IT system have been changed.

4.9.2. The EMA will continuously monitor developments in the industry and the effectiveness of the IPM. In addition, the EMA will review the parameters over time to take into account entry of other IGS technologies (such as wind and tidal)[20], development of more technologies that can address intermittency, improved solar forecasting, modelling accuracy, procurement of regulation and spinning reserves and the level of IGS deployment.

[19] New Energy Outlook 2018, Global Key Messages Presentation, Bloomberg New Energy Finance

[20] Should such non-solar technologies become feasible in Singapore and enter the market eventually, the EMA will review their specific treatment in the IPM framework, taking into consideration their characteristics and technical parameters.

ANNEX 1: Regulation/Reserves charging in overseas jurisdictions

Country	Approach
Australia[21]	• The need for regulation and reserves are determined by "Contribution Factors" for all generators and loads, based on variability and uncertainty. • Payments for Frequency Control Ancillary Services (FCAS) are recovered from generators and loads in proportion to their negative contribution factors.
Spain[22]	• All generators including wind and solar, are responsible for paying for the costs of any schedule deviations and the costs of the regulation and reserves necessary.
Denmark[23]	• Market participants automatically trade the deviation with the Transmission System Operator (TSO) if it does not generate or consume the amount of electricity agreed in the spot market. • The expenses paid by the TSO for regulation and reserves are transferred to the participant responsible for the imbalance.
United States (California)[24]	• In California, the system operator (CAISO) allocates the costs of contingency reserves to scheduling coordinators (who represent load, imports and exports).

[21] Frequency Control Ancillary Services, Centre for Energy and Environmental Markets, 2013
[22] PJM Renewable Integration Study, Exeter Associates, Inc. and GE Energy, 2014
[23] Currents of Change, IEEE Journals & Magazine, 2011
[24] Tariff Amendment – Contingency Reserve Cost Allocation, CAISO, 2014

ANNEX 2: Detailed Derivations of Estimated Maximum Power Reduction (EMPR) for IGS, specifically Solar PV

1. The aggregated solar PV generating unit output (MWac) is estimated using solar global horizontal irradiances (W/m^2) measured from solar irradiance sensors installed island-wide across Singapore, and the solar PV registry maintained by SPPG.

2. The output reduction of the aggregated solar PV generating unit output (MWac) within a thirty-minutes dispatch period is computed for all the periods in a year. There are a total of 365 samples of output reductions for every specific period, e.g. period 24, in a typical year.

3. The period-based EMPR of the aggregated solar PV generating unit (MWac) is the maximum reduction among the 365 reduction samples.

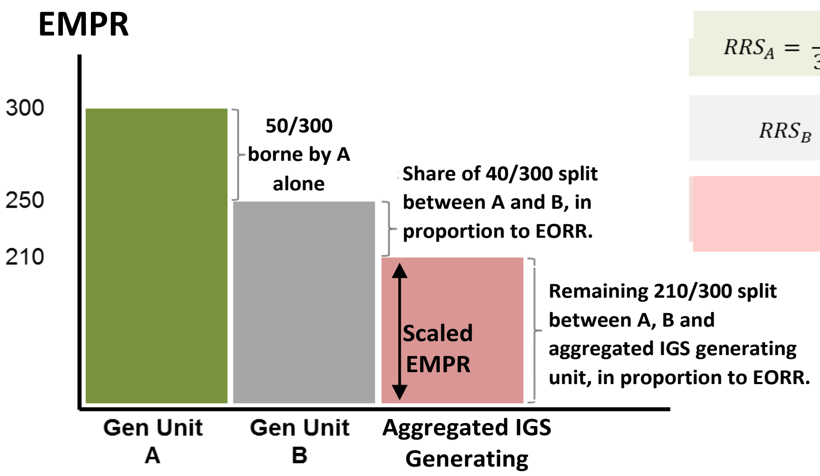
$$\boldsymbol{EMPR}_{\,\boldsymbol{Period}\ \mathbf{24}}\ (\boldsymbol{MWac}) \\ = \boldsymbol{Maximum}\left\{\boldsymbol{Reduction}_{\,\boldsymbol{Day}\ \mathbf{1},\ \ \boldsymbol{Period}\ \mathbf{24}}, \boldsymbol{Reduction}_{\,\boldsymbol{Day}\ \mathbf{2},\ \ \boldsymbol{Period}\ \mathbf{24}\ \ldots}, \boldsymbol{Reduction}_{\,\boldsymbol{Day}\ \mathbf{365},\ \ \boldsymbol{Period}\ \mathbf{24}}\right\}$$

4. The period-based EMPR (MWac) is normalised to the total solar PV installed capacity (MWac), including the capacity of the installations not subjected to IPM. The capacity of the installations not subjected to IPM is included to account for the aggregated risk imposed by all the grid-connected solar PV installations on the electricity grid. This period-based EMPR (%) is computed on an annual basis.

$$\boldsymbol{EMPR}_{\,\boldsymbol{Period}\ \mathbf{24}}\ (\%) = \frac{\boldsymbol{EMPR}_{\,\boldsymbol{Period}\ \mathbf{24}}\ (\boldsymbol{MWac})}{\boldsymbol{Total\ Installed\ Capacity}\ (\boldsymbol{MWac})}$$

5. The period-based EMPR (%) will be scaled, on a monthly basis, in accordance to the aggregated solar PV generating unit size, and applied in the calculation of the RRS in the modified runway model.

$$\boldsymbol{Scaled\ EMPR}_{\,\boldsymbol{Period}\ \mathbf{24}}\ (\boldsymbol{MWac}) = \boldsymbol{EMPR}_{\,\boldsymbol{Period}\ \mathbf{24}}\ (\%) \times \boldsymbol{Solar\ PV\ Generating\ Unit\ Size}\ (\boldsymbol{MWac})$$



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

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

$$RRS_{IGS} = 0.33 * \frac{210}{300}$$

*Assumes equal EORR for the 3 generating units.

6. EMA has launched a research grant to develop solar forecasting capability, with the aim to accurately predict the aggregated solar PV output. Once the solar forecasting capability is established, the forecasted aggregated solar PV output could replace the aggregated solar PV generating unit size, in the formula to determine the period-based EMPR (%).

$$\boldsymbol{Scaled\ EMPR}_{\ \boldsymbol{Period\ 24}}\ (\boldsymbol{MWac}) = \boldsymbol{EMPR}_{\ \boldsymbol{Period\ 24}}\ (\%)\ \times \boldsymbol{Forecasted\ Solar\ PV\ Output}_{\ \boldsymbol{Period\ 24}}\ (\boldsymbol{MWac})$$

ANNEX 3: Detailed Derivations of Expected % Output Reduction Rate (EORR) for IGS, specifically Solar PV

1. The aggregated solar PV generating unit output (MWac) is estimated using solar global horizontal irradiances (W/m^2) measured from solar irradiance sensors installed island-wide across Singapore, and the solar PV registry maintained by SPPG.

2. The output reduction of the aggregated solar PV generating unit output (MWac) within a thirty-minutes dispatch period is computed for all the periods in a year. There are a total of 17,520 (i.e. 365 x 48) samples of output reductions, in a typical year.

3. All the 17,520 samples of output reductions in a year are normalised to the total solar PV installed capacity (MWac), including the capacity of the installations not subjected to IPM. The capacity of the installations not subjected to IPM is included to account for the aggregated risk imposed by all the grid-connected solar PV installations on the electricity grid.

$$\boldsymbol{Output\ Reductions}\ (\%) = \frac{\boldsymbol{Output\ Reductions}\ (\boldsymbol{MWac})}{\boldsymbol{Total\ Installed\ Capacity}\ (\boldsymbol{MWac})}$$

4. For all the output reductions (MWac) that are above 10MWac, the output reductions (%) are summed up and divided by the total number of online periods multiplied by 100%.

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

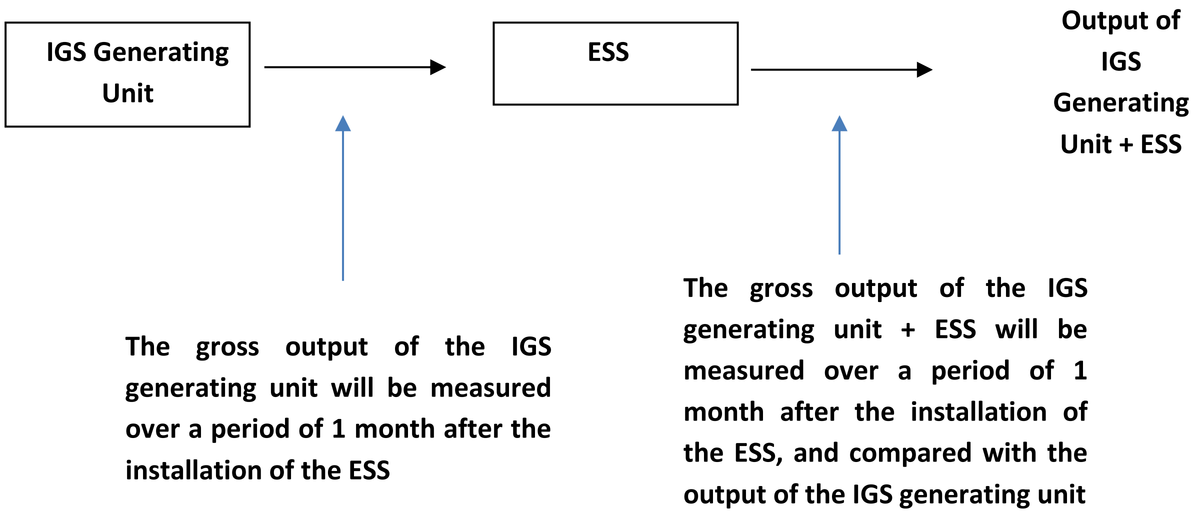
$$= \left[\sum_{\boldsymbol{i=1}}^{\boldsymbol{C}} \text{Output Reduction}_i\ (\%)\right] \Big/ \boldsymbol{C}$$

where, C refers to the total number of online periods x 100%. An online period for the aggregated solar PV generating unit refers to a period where the aggregated solar PV generating unit is producing power, typically from 7am to 7pm daily.

5. The EORR is computed quarterly, based on data gathered over a moving one-year window, similar to the current PoF calculation, and is applied in the calculation of the RRS in the modified runway model (refer to Annex 2, paragraph 5).

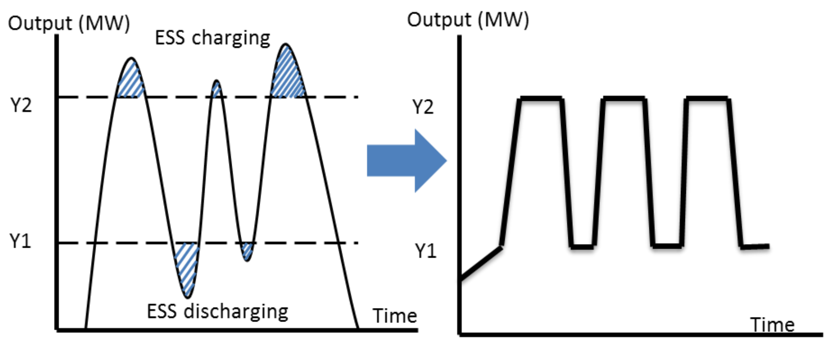
ANNEX 4: Proposed treatment of ESS or other solutions that mitigate IGS intermittency under IPM

1. To accurately determine how the ESS (or other technological solutions) could reduce the EMPR and EORR of the IGS generating unit, the gross output of the IGS generating unit and the gross IGS generating unit (coupled with ESS) output will be measured over a period of 1 month, after the installation of the ESS.

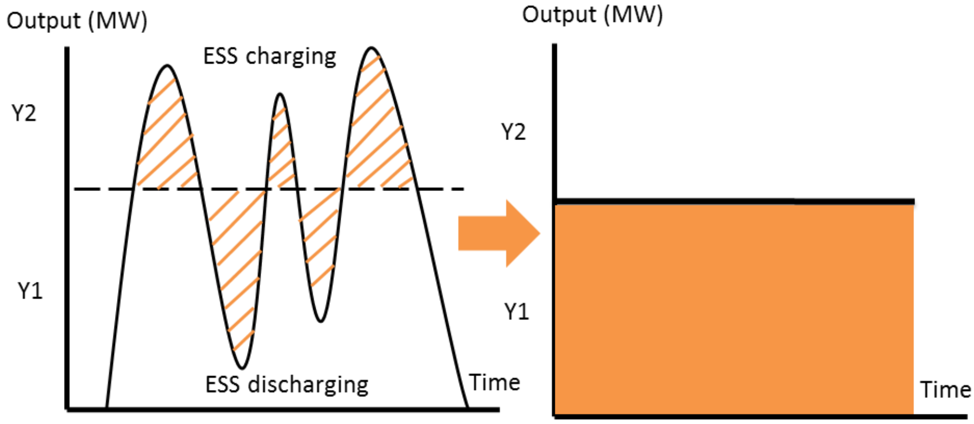


2. Depending on whether the gross output of the IGS generating unit (coupled with ESS) is partially intermittent or fully dispatchable, their treatment in the modified runway model will be different.

   a) If the IGS generating unit coupled with ESS is not fully dispatchable, it will be aggregated with other IGS units and the reserves cost will be allocated respectively among all IGS units based on the individual IGS unit's estimated maximum power reduction (EMPR).



b) If the IGS + ESS is fully dispatchable akin to a conventional generator, it will be treated separately from other IGS units, and the reserve cost will be allocated respectively like a conventional generator (i.e. based on the EMPR and expected % output reduction rate vis a vis other generators in the system).



4. The EMA is open to the industry's views and feedback on ways to ensure fair allocation of reserves cost to IGS that is coupled with solution(s) that mitigate IGS intermittency.

ANNEX 5: Estimated Costs[25] under IPM at different levels of IGS Capacity

Parameters	Estimated Costs at Different Levels of IGS Capacity					
Total capacity incl. grandfathered projects [26](MWac)	**300**	**400**	**600**	**1,000**	**1,200**	**2,000**
IGS Regulation costs[27] ($/MWh)	0.06	0.04	0.02	0.01	0.01	0.01
IGS Spinning reserve costs[28] ($/MWh)	1.44	1.89	2.32	2.67	2.76	2.91
Total reserve costs faced by a fully intermittent IGS ($/MWh) [29]	1.50	1.93	2.35	2.68	2.77	2.92
Total reserve costs faced by a 20 MWac IGS with ESS (Partially intermittent)[30] ($/MWh)	0.76	0.97	1.18	1.35	1.39	1.46
Total reserve costs faced by 20 MW from conventional gencos ($/MWh)[31]	2.03					
Fully Intermittent IGS' reserve costs as % of retail price[32]	0.8%	1.0%	1.3%	1.5%	1.5%	1.6%

[25] The estimated costs are developed based on the stated assumptions and historical prices. The actual costs will be subject to prevailing market conditions and future advancements.
[26] Assumes that the following IGS is grandfathered across all scenarios (i) ~108 MWac capacity of non-residential IGS (connected on or before 31 Jan 2018) and (ii) ~5% of total IGS capacity is residential. Solar PV's EORR assumed to be 7.65%. The average ramp down rates, for each half-hour sunny dispatch periods, are based on solar irradiance data from 2016.
[27] Estimated based on average Allocated Regulation Price (AFP) over 2013-2017.
[28] Estimated based on average spinning reserve costs from 2013-2017.
[29] The total reserve costs include regulation and spinning reserve costs.
[30] We assume that when the IGS installation is paired with ESS, the max loss is reduced by 50%.
[31]The reserve costs faced by a conventional 400 MW CCGT running at 50% load factor with a low EORR of 0.18%. Estimated based on average Allocated Regulation Price (AFP) and average spinning reserve costs from 2013-2017.
[32] Based on the average retail price of ~$177.2/MWh for LT C&I consumers in 2017. Consumers avoid the retail price when they consume generation from their IGS installation.

Fully Intermittent IGS' Reserve costs as % of LCOE of IGS[33]	1.3%	1.7%	2.1%	2.4%	2.5%	2.6%

[33] Based on the Solar Energy Research institute of Singapore (SERIS)'s LCOE estimates for an industrial 1 MWp solar PV system at ~$110/MWh in 2017.