



CONSULTATION PAPER

REVIEW OF POLICY ON DIRECT SUPPLY OF ELECTRICITY BY GENERATING SETS TO ONSITE LOADS

Closing date for submissions of comments and feedback:
16 Dec 2009

Note: There will be no extension of deadline beyond 16 Dec 2009, 5 pm

18 NOV 2009	ENERGY MARKET AUTHORITY 991G Alexandra Road #01-29 Singapore 119975 www.ema.gov.sg
-------------	--

Disclaimer:

The information in this Consultation Paper is not to be treated by any person as any kind of advice. The Energy Market Authority shall not be liable for any damage or loss suffered as a result of the use of or reliance on the information given in this Consultation Paper.

1 Introduction

1.1 Currently a company is allowed to embed generation, i.e. install generating units to generate and supply electricity directly to its load facilities provided that:

- (a) the embedded generating units are located on land which is contiguous to the load facilities; and
- (b) the embedded generating units, load facilities and land are majority (i.e. at least 50%) owned by the same company.

If the company does not export electricity into the power grid, it will be given net treatment for non-reserve market charges, i.e. Energy Market Company (EMC) fees, Power System Operator (PSO) fees, Monthly Energy Uplift Charge (MEUC) & Market Support Services (MSS) charge. In other words, the non-reserve market charges are levied on the company based on its net import of electricity.

1.2 A company may also install the embedded generating units on land that is *non-contiguous* with its load facilities and/or *outsource* the embedded generating units by engaging third parties to develop, own and operate the embedded generating units, provided that:

- (a) there is no contiguous land available for the company to accommodate the embedded generating units and load facilities;
- (b) the load facilities and the land on which the load facilities and embedded generating units are located (i.e. including the non-contiguous land if applicable) must be majority-owned by the same company; and
- (c) there is a point-to-point (i.e. dedicated) electrical connection between the embedded generating units and load facilities.

However, EMA will not allow outsourcing of embedded generating units to a company if this creates market power or adds to existing market power of the company.

2 Review of Policy on Direct Supply of Electricity

- 2.1 In 2008, the Government had appointed a consultant, NERA Economic Consulting ("NERA") to conduct a comprehensive review of the electricity market. The review covered *inter alia* policy issues pertaining to embedded generators (EGs).
- 2.2 Arising from this review, NERA assessed that there was an artificial bias towards EGs due to the way grid charges are structured. More specifically, grid charges today consist of a fixed component (the contracted capacity charge or kW charge) and a variable component (kWh charge). On the whole, the latter currently accounts for around 25% of grid charges. Consequently, companies may find it more attractive to build their own generators in order to save on this variable component of grid charges. Hence NERA recommended that this artificial incentive be removed by shifting towards a 100% fixed charging regime.
- 2.3 EMA agrees in principle with NERA's recommendation and intends to shift the balance of grid charges towards a fixed charging regime. We will do this progressively through the annual review of grid charges, taking into consideration the impact of any such changes on consumers.
- 2.4 NERA also proposed changes to streamline current rules, simplify and remove restrictions, and introduce market mechanisms where possible, so as to enhance the efficiency of the market and ensure clearer price signals to investors.
- 2.5 EMA broadly agrees with the NERA approach, which is for the deployment of EGs to be driven by the market. After reviewing NERA's recommendations and initial consultations with industry stakeholders, EMA proposes to make the following changes to the policy on direct supply of electricity.

2.6 Net Treatment of Non-Reserve Charges for Embedded Generators

2.6.1 Currently, only EGs that do not export electricity to the power grid will get net treatment on non-reserve charges. For example, a 30MWh EG with a 50MWh onsite load (and therefore draws only 20MWh from the system) will need to pay non-reserve charges based on its net import of 20MWh. However, a 10MWh EG with 8MWh onsite load (and therefore exports 2MWh to the power grid) will need to pay non-reserve charges based on its gross load of 8MWh and gross generation of 10MWh.

2.6.2 We propose that all EGs be granted net treatment on non-reserve charges regardless of whether they export electricity to the power grid. Allowing EGs on net treatment to export electricity would enable EGs to optimize their operation and enhance competition in the electricity market. Hence in the example of the 10MWh EG with 8MWh onsite load, the EG will need to pay non-reserve charges based on its net export of 2MWh only. A more detailed illustration of the difference in treatment is shown below.

Example

Non-reserve charges for a 10MWh EG with 8MWh onsite load (and therefore exports 2MWh to the power grid) under the current and new treatments:

Under current treatment:

Non-reserve charges	Allocation of MWh to:	
	Generation	Load
Energy Market Company (EMC) Fees	10	8
Power System Operation (PSO) Fees	10	8
Market Support Services (MSS) Charge	0	8
Monthly Energy Uplift Charge (MEUC)	0	8

Under new treatment:

Non-reserve charges	Allocation of MWh to:	
	Generation	Load
EMC Fees	2	0
PSO Fees	2	0
MSS Charge *	0	0
MEUC *	0	0

* As the MSS charge and the MEUC are borne only by loads, the EG will not have to pay any MSS charge or MEUC under the new treatment

2.7 Gross bidding of Embedded Generators

2.7.1 Currently, all generators (including EGs) with aggregate capacity of more than 10MW are required to bid their gross generation capacity into the market regardless of whether they wish to export power or not. This is to allow the market clearing engine to schedule generation and reserve so as to ensure the balance between electricity demand and supply.

2.7.2 The gross bidding obligation means that an EG would have to sell all its power to the market and then buy it back for its own use, even though the electrons do not leave its fence. This obligation imposes additional costs on the EGs to interact with the wholesale electricity market and administer the related transactions. Stakeholders have commented that this obligation is onerous and does not benefit the market. As such, we propose the following changes:

- (i) the obligation to bid into the market will be removed entirely for EGs which do not export electricity. Instead, these EGs will be required to furnish specified information pertaining to their generation quantities for their own use to the EMC and PSO on an *ex-ante* basis and at their own cost. The quantities of generation for EGs' own use will be treated as the 'must run' quantities in the market clearing engine (MCE); and

- (ii) for EGs that intend to export electricity, they will be required to bid into the market only for the 'export' quantities, and they have to provide the specified information pertaining to their generation quantities for their own use to the EMC and PSO on an *ex-ante* basis and at their own cost.

2.7.3 The EGs shall continue to provide to the PSO real time information to enable PSO to maintain secure operation of the power system. The information required includes (but not limited to) EGs' active & reactive power, voltage & frequency at each generator's terminal, active & reactive power flow through the service connection to the power grid, and gas demand.

2.8 Non-Frequency Responsive (NFR) Cap

2.8.1 EGs typically use co-generation or tri-generation plants that are usually non-frequency responsive (NFR), i.e. their plant output does not respond to changes in system frequency, and therefore cannot provide reserves. Currently, there is a cap (in MW) on total NFR generation capacity that is allowed to be installed in the system. Imposing an absolute cap on NFR generation capacity would disadvantage future investors. A market-based solution is preferable to the administrative cap in allocating NFR capacity among NFR generators including the EGs. As such, we propose to replace the current NFR cap with a suitable market mechanism and to give PSO the power to 'back-off' EGs' 'must run' generation quantities during system emergencies to maintain secure operation of the power system.

2.8.2 Specifically, the market mechanism will be implemented by way of a security constraint imposed in the MCE. This algorithm will replace the existing NFR cap. In other words, for each dispatch period, the MCE will be run to schedule the dispatch of all generators – both frequency responsive and non-frequency responsive – while ensuring adequate reserves for system security.

2.8.3 Under such an arrangement, there is a possibility that NFR EGs or other NFR generators may not get dispatched, as the MCE would optimise the scheduling of generators in order to maintain adequate reserves for secure operation of the power system. If this happens, the MCE would 'back-off' the EGs' 'export' quantities and other NFR generators' quantities first (based on their bid prices) and the EGs' 'must run' quantities last (based on a tie-breaking mechanism). The tie breaking mechanism is required should the total 'must run' quantity of all EGs exceed the amount of NFR capacity allowed by the MCE. We propose a mechanism such that the MCE 'backs-off' EGs on a pro-rated basis (see example below of how such a pro-rating mechanism would work). However, EMA is open to other feasible tie-breaking mechanisms and would like to invite comments and suggestions on this proposal.

Example

For a despatch period, EGs' total 'must run' quantity exceeds the security constraint and there is a need to 'back-off' 10MWh of 'must run' NFR generation to maintain secure operation of the power system. Assume that the 'must run' quantities for that despatch period submitted to EMC are as follows:

Company A:	5 MWh
Company B:	3 MWh
Company C:	200 MWh
Company D:	50 MWh
Total:	258 MWh

The 'must run' quantities that the MCE would 'back-off' for each EG are:

Company A:	$5/258 * 10 = 0.19$ MWh
Company B:	$3/258 * 10 = 0.12$ MWh
Company C:	$200/258 * 10 = 7.75$ MWh
Company D:	$50/258 * 10 = 1.94$ MWh
Total:	10 MWh

2.9 Automatic Penalty Scheme

2.9.1 Under the current market rules, the Market Surveillance & Compliance Panel (MSCP) assesses and imposes penalties on unscheduled generation on a case-by-case basis. We propose to implement an automatic penalty scheme for all Generation Registered Facilities (GRFs) that deviate from their dispatch schedule. With an automatic penalty system, there would be clearer signals to generators and the MSCP need not conduct investigations into such routine cases.

2.9.2 The proposed scheme shall apply to all GRFs (including EGs) that are not on Automatic Generator Control (AGC). The methodology is such that when the actual metered energy deviates by more than 10% from the scheduled energy, the defaulting generator will be imposed with a penalty of 2 times the Value Of Lost Load (VOLL), i.e. $2 \times \$5000/\text{MWh} = \$10,000/\text{MWh}$. The penalty collected will be returned to the market through the MEUC. A worked example is shown below.

Example:

Actual metered energy for a dispatch period: 80MWh or 120MWh

Scheduled energy for the dispatch period: 200MW

(i.e. 100MWh for the dispatch period)

% deviation = 20%

Penalty = $10\text{MWh} \times \$10,000/\text{MWh} = \$100,000$

(first 10% deviation will not be penalised)

The penalty would serve as a deterrent to ensure that GRFs do not deviate by more than 10% from their dispatch schedule.

3 Implementation timeline

Modifications to the Market Rules and the IT systems for the MCE and the market settlement system will be required to implement the above proposals. Once implemented, the new rules shall apply to all existing and new EGs. The indicative implementation timeline is given in the table below.

Date	Item
18 Nov 2009	EMA publishes consultation paper
16 Dec 2009	Deadline for submission of comments to EMA
Feb 2010	EMA publishes responses to feedback and final decision
Nov 2010	Completion of Market Rule changes and IT system modifications
Dec 2010	Implementation of changes

4 Requests for comments and feedback

4.1 EMA invites comments and feedback to the proposals in this Consultation Paper. Please submit all feedback, in writing, to Mr Henry Wong (henry_wong@ema.gov.sg) or Ms Sharon Chuo (sharon_chuo@ema.gov.sg).

Alternatively, you may send the submissions by post/fax to:

*Economic Regulation & Licensing Department
Regulation Division
Energy Market Authority
991G Alexandra Road, #02-29
Singapore 119975
Fax: (65) 6 835 8020*

4.2 Please note that any anonymous submissions will not be considered. 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. EMA will take this into account regarding disclosure of the information submitted.