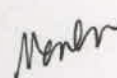


MINUTES OF THE 80th MEETING OF THE RULES CHANGE COMMITTEE	
Meeting Date & Time:	06 November 2013 – 09:00 AM to 3:15 PM
Meeting Venue:	PEMC Board Room, 18 th Board Room, Robinsons Equitable Tower, Ortigas Center, Pasig City
Attendance List	
In-Attendance	Not In-Attendance
Rules Change Committee Members Rowena Cristina L. Guevara --Chairperson/ Independent --UP Francisco L. R. Castro, Jr. --Independent--Tensaiken Consulting Maila Lourdes G. De Castro --Independent Concepcion I. Tanglao --Independent Joselyn D. Carabuena --Generation -- PSALM Jose Ferlino P. Raymundo --Generation -- SMC Global Ciprinilo C. Meneses--MERALCO Gilbert A. Pagobo --Distribution --MECO Jose P. Santos --Distribution --INEC Sulpicio C. Lagarde, Jr. --Distribution --CENECO Isidro E. Cacho, Jr. -- Market Operator --PEMC Ambrocio R. Rosales --System Operator --NGCP Theo Cruz Sunico --Generation -- 1590 EC	Lorreto H. Rivera --Supply -- TeaM (Philippines) Energy Corporation
Rules Change Committee Alternate Members Edwin N. Mosa --Market Operator-- PEMC	
PEMC – Market Assessment Group (MAG) Geraldine A. Rodriguez Romellen C. Salazar PEMC – Legal Caryl Miriam Y. Lopez-Mateo Maria Lourdes Sabundayo San Andres PEMC – Finance Marissa P. Gandia PEMC – TOD Marcial Brummel J. Jimenez Edward I. Olmedo Arthur P. Pintado	
ERC Observer(s) Isabelo Joseph P. Tomas	





DOE Observer(s)
Ferdinand B. Binondo

Others Present

There being a quorum, Chairperson Dr. Rowena Cristina L. Guevara called the meeting to order at around 9:00 AM.

1. Adoption of the Proposed Agenda

The Proposed Agenda for the 80th RCC Meeting was approved, as amended, with the removal of the item on Proposed NSS Manual under New Business. The Secretariat informed the RCC that the matter was withdrawn based on more recent directions of the PEM Board.

The Secretariat likewise requested the inclusion of the letter of NGCP in relation to the MRU as Ancillary Service.

2. Review, Correction, and Approval of the Minutes of the 79th RCC Meeting

The Minutes of the 79th RCC Meeting was approved, as amended. Corrections made are as follows:

- On page 1:
"Team ~~M~~ **(Philippines)** Energy Corporation"
- On page 5, line 48:
"She added that those who were not able to get contracts with other ~~Customers~~ **Generators** but continue to draw from the WESM are automatically attached with PSALM."
- On page 5, line 12:
"In response to the first suggestion of Mr. Lagarde, Dr. Guevara opined that the WESM members should be able to realize the interplay in the market, ~~and accept the way the market works, to include the fees involved in being a member of the WESM, even without drawing power from the grid. the corresponding effect on prices, and the costs involved in being a member of the WESM.~~ She suggested that the matter be discussed among the WESM members particularly in Visayas, for their **enlightenment** appreciation."
- On page 15, line 25:
"Dispatch of MRU ~~or MOT re-dispatch~~ should be done only after the A/S or Reserves are exhausted."
- On page 15, line 30-32:

- "MRU is different from MOT Redispatch (Constrained~~ed~~-on/off)
 - MRU from Offline
 - Constrained~~ed~~ on/off – synchronized to the grid

➤ On page 18, line 30:

"She added that the DOE directive is not necessarily to include the inclusion of the MRU as part of the ASPP. As long as the SO calls an MRU, it should be paid by the SO as ancillary. She clarified that when a generator is declared called as MRU..."

➤ On page 23, line 29:

"Ms. Joselyn Carabuena inquired whether the approval of the ERC is required every time the MO or the SO declares issues a market intervention. Mr. Cacho clarified in response that intervention is declared by the MSO, in coordination with the MO, when the MO is unable to produce RTD schedules or when the RTD schedules cannot be implemented due to system security issues when there is no generation of schedules, and such could happen anytime, thus, there is no prior approval by the ERC for the same, but rather, a post-reporting by the MO to the ERC, PEM Board, and other concerned. He added that the ERC is involved only during market suspension, being the one that declares such."

➤ On page 23, line 38:

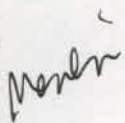
"Ms. Rivera commented that the market intervention as a result of the MO's drill may affect prices. In such case, since there will be is no generation no RTD schedules,..."

Following the RCC's review of the subject Minutes and noting the corrections made on the same, the Minutes of the 79th RCC Meeting held on 02 October 2013 was approved, as amended.

3. Business Arising from the Previous Meeting

◦ DOE Transmittal Letter to GMC re the RCC-Proposed Amendments to PGC

Dr. Guevara shared that the DOE in the subject letter, endorsed the RCC proposal to GMC to amend the Philippine Grid Code. Relatedly, she reminded the members of the DUs and ECs, relative to their proposal on the cap in transmission losses previously raised by the DU sector during the RCC deliberations on the PGC amendments. Mr. Gilbert A. Pagobo responded that the DUs are intending to submit the same by December 2013. Mr. Ferdinand B. Binondo shared relative to the matter that the deadline for submission of all proposed amendments to the PGC has already lapsed. However, he stated that the matter on the transmission price cap is already included in the proposal by the Distribution Management Committee (DMC) and was likewise tackled during the public consultation held in Cebu. The information was duly noted by the DU representatives and members of the RCC. Noting the information from the DOE, the RCC agreed that the submission of the proposal previously agreed upon by the RCC with members of the DUs and the ECs is no longer necessary.



1 o **Updates on the Revised Proposal on the WESM Rules and the Billing and**
2 **Settlement Manual relative to Prudential Requirement**

3
4 Atty. Maila De Castro apprised the RCC regarding the recent development on the PR
5 proposal following the PR sub-committee's discussion on the matter. She stated that
6 the remaining issues to be discussed by the RCC are as follows:

- 7
8 i. Inclusion of notification to the NEA as suggested by the PEM Board;
9 ii. Issue on the basis of computation of ME for the generators that became net
10 buyers; and
11 iii. Definition of the term "Disputed bill"

12
13 Atty. De Castro stated that during the sub-committee discussion on the matter on
14 Prudential Requirement, the body agreed to replace the term "disputed," with
15 "disagreement," to refer to any disagreement by the Trading Participant to what has
16 been billed by the WESM. For clarity, Atty. De Castro stated that such bill is not
17 something that has reached the level of the dispute resolution process by the WESM.

18
19 In relation to the notification to the National Electrification Administration (NEA) as
20 suggested by the PEM Board, Atty. De Castro stated that the sub-committee
21 proposed a provision that covers all appropriate regulatory bodies, instead of limiting
22 such notification to NEA, should this be necessary. Dr. Guevara commented that the
23 NEA is not a regulatory body, rather, an administrative body which supervises the
24 operation of electric cooperatives. In this regard, the RCC agreed to revise the
25 provision proposed by the sub-committee to include in the provision the notification to
26 the "administrative bodies" instead of merely the regulatory bodies. The proposed
27 provision should then read, as follows:

28
29 3.4.11.2 Immediately issue a suspension notice in accordance with clause 3.15.7 if
30 the *Market Operator* considers that the default is not capable of remedy and that
31 failure to issue a suspension notice would be likely to expose other *WESM members*
32 to greater risk, and notify in writing the appropriate administrative and
33 regulatory bodies concerned of such suspension; and/or
34 xxx

35
36 Relative to the computation of prudential security for net buyer generators, Atty. De
37 Castro presented the proposed provisions crafted by the PR sub-committee, as
38 follows:

39
40 3.15.2.4 (new). A WESM member who is exempted from providing a security
41 deposit under clause 3.15.2.2 shall be required to pay the total negative
42 settlement amount due, if any, within three working days before the due date as
43 provided under Clause 3.14.6.

44
45 3.15.2.5 (new). Failure to comply with clause 3.15.2.4 shall be a ground for
46 cancellation of exemption and the WESM member shall be assessed and be
47 required to put up prudential requirement.
48 Upon written request of the WESM member, the Market Operator may lift the
49 cancellation of exemption from prudential requirement, provided that the WESM
50 member:
51 a) has settled all its outstanding obligations including interest, if any; and
52 b) has no record of default in payment or non-compliance with the PR for the
53 immediately preceding six (6) billing periods from the cancellation of
54 exemption.
55

Additional provisions on the refund of security were also included in the proposal, as follows:

3.15.3 Refund of Security (new insertion)

Upon written request from the WESM member, the Market Operator shall refund the prudential security under the following conditions:

a) if the Market Operator has lifted the cancellation of suspension after the WESM member complied with its obligations under Clause 3.15.2.5 ; or

b) if the security deposit of a WESM Member consistently exceeds the Maximum Exposure in previous six (6) consecutive billing periods.

The refund of security deposit shall be allowed by the Market Operator after the assessment of the amount of refund, provided that the WESM Member has no record of default and non-compliance with the prudential requirement in previous six (6) consecutive billing periods

Dr. Guevara clarified that the provision being proposed covers generators that become net buyers. She emphasized that such provision is applicable specifically to the net buyer generators that fail to settle the amount due, stating further that with the proposed provision, net buyer generators should be able to pre-pay the amount due before the due date in order to avoid the cancellation of exemption as provided under WESM Rules Section 3.15.2.

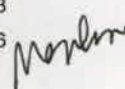
Atty. De Castro shared that during the discussions on the matter, it was raised that in the absence of negative settlement amounts in the historical data of a particular generator for the previous six (6) months, the data during earlier periods shall be considered in computing for the required prudential security of that generator. Dr. Guevara consulted with the generator representatives regarding the proposal, whether the same is acceptable to them. The generator representatives concurred with the proposed provisions as crafted by the sub-committee and as deliberated upon the RCC.

Following the discussions, the RCC agreed on the proposed provision regarding computation of prudential security for net buyer generators.

Moving forward with the discussion, Ms. Geraldine Rodriguez, stated that as a matter of procedure and considering the material changes made on the initial proposal submitted to the PEM Board, the revised proposed revisions to the WESM Rules and the Billing and Settlement Manual relative to Prudential Requirement will need to be re-posted in the WESM Market Information Website for comments. The RCC noted the information. Dr. Guevara suggested that when the proposal is posted in the website, the additional proposed revisions be highlighted to emphasize that only the additional provisions are open for comments, as the other provisions covered in the proposal were already previously posted for comments of participants

The RCC then reviewed whether the following PEM Board instructions to the RCC were complied with and included in the additional provisions crafted by the RCC:

- 1) Making an equivalent provision that would require net buyer generators to either post a prudential security or to pre-pay its account before due date, whichever may be applicable. An**





1 explanation is also requested to be included in the report on the
2 reason why the matter was not considered at the first instance
3 the proposal was submitted.

4
5 > The RCC agreed that said provision instructed by the PEM Board is
6 already covered in the revised RCC proposal. Relative to the
7 explanation on why the same was not included in the first instance
8 that the proposal was submitted to the PEM Board, the RCC agreed
9 that the same was not considered in view of the information given that
10 offsetting is currently being practised in the settlement of the bill of net
11 seller generators. In this regard, it was decided that a provision
12 requiring net buyer generators to post a prudential security is no
13 longer necessary due to this off-setting in the bill of the generator/s in
14 the following month. The RCC added that when the matter was initially
15 discussed, the RCC had no information/data showing that there were
16 in fact generators that have actually become net buyers in the past
17 billing months.

- 18
19 2) As discussed that the basis for PR as applied to the DUs may not
20 necessarily be applicable for net buyer generators, it was
21 suggested that alternative mechanisms on how to address the
22 risks (generators being net buyers) be explored by the Rules
23 Change Committee.

24
25 > The RCC noted this is already covered in the revised proposal which
26 considered the last six billing months, or in the absence thereof, the
27 available data during early periods.

- 28
29 3) On the matter of PR for the DUs, the PEM Board would like to be
30 clarified on in the basis for setting the PR at ten (10) percent of
31 the demand for WESM members who are fully covered by
32 bilateral contracts.

33
34 > The RCC noted that the basis of the 10% is the provision in the
35 EPIRA.

36
37 Relative to item 3) above, the DUs noted that the 10% provision in the EPIRA has a
38 prescriptive period of five (5) years, which period has already lapsed. Mr. Meneses
39 opined that the amount most appropriate to be used as the basis for setting the PR
40 is the amount corresponding to line rental. He explained that even if the DU is 100%
41 contracted, it will still be subject to line rental. Thus, the amount of line rental should
42 be the basis for setting the DUs' prudential security. In relation to the matter, Dr.
43 Guevara commented that the Prudential Requirement is not just a guarantee for
44 payment to the NGCP, but for the generators as well, noting that when net buyer
45 generators fail to pay its settlement amounts in cases where said generators become
46 net buyers, the prudential security shall cover the payment to other generators.

47
48 Further to the discussion, Ms. Marissa Gandia clarified that the PEM Board, in its
49 directive, was merely asking for the basis of the computation. As such, whether the
50 RCC proposed to have it at 8% or 12% or any number, it should be able to provide a
51 basis for its computation, and in the case of the RCC-approved proposal, the 10%
52 requirement. She stated that if the DUs deem that the 10% is no longer applicable,
53 then the sector can later on submit another proposal to change the basis of the



1 computation. She suggested, however, to already push through with the 10% as
2 previously agreed upon by the RCC.

3
4 Mr. Pagobo expressed that the 10% basis of PR is no longer a valid reference,
5 sharing with the RCC that based on their own experience, they are always called to
6 increase their PR, which computation is based on the 10% requirement, every time
7 their spot transactions go over their contracted quantities. He therefore suggested
8 that the DUs be allowed to change the proposed 10% computation of the DUs' PR.
9 Mr. Lagarde, on the other hand, opined that the 10% is still acceptable. He said that
10 his reservation is only with the possibility of increasing the 10% basis which he
11 thought would already be burdensome for the DUs and the ECs to take.

12
13 Atty. Isabelo P. Tomas stated that the 10% requirement in the EPIRA was
14 envisioned to support the market at the early phase of its implementation. This meant
15 that even those covered by bilateral contracts should be able to source at least 10%
16 of its demand from the WESM. Thus, that 10% demand should be the subject of the
17 prudential security. He explained further that the 10% is a requirement for
18 participating in the market rather than a basis for the PR in this context. Thus, it may
19 not be totally accurate to say that the basis of the 10% Prudential Requirement is the
20 EPIRA.

21
22 In response to the above concern raised by Atty. Tomas, the RCC referred to clause
23 3.2.2.4 of the WESM Rules with regards the computation of the PR. The RCC then
24 agreed to cite said provisions in providing the basis of the 10% proposal, further
25 agreeing that since the concern of the PEM Board is to be given basis for the
26 computation, said proposal is already sufficient to justify such.

27
28 Ms. Gandia added that if the DUs can provide a basis that their PR should be a
29 number less than 10%, then that is probably the only time that they can propose to
30 change the 10% requirement.

31
32 Mr. Pagobo suggested that before the proposal is submitted to the PEM Board, the
33 DUs be given another month to craft its proposal relative to the basis of the
34 computation of the DUs' PR. Mr. Pagobo stated that the same will be presented in
35 the next RCC meeting.

36
37 However, considering that the proposal has long been hanging with the RCC and
38 since the specific instruction of the PEM Board when the matter was referred back to
39 the RCC was only to provide basis for the 10% computation, it was agreed by the
40 majority for the RCC to retain its proposal and push through with the posting of the
41 same to solicit comments only on the additional amendments arising from the
42 instructions by the PEM Board. As for the proposal that the DUs intend to submit
43 regarding changing the 10% requirement, Dr. Guevara suggested that this be
44 submitted through a different proposal which the RCC can bring to the table. She
45 further suggested that the other members of their sector be consulted so that when
46 the proposal is submitted to the RCC and the matter is deliberated, it is ensured that
47 the inputs of the other members of the sector are considered.

48
49 In summary, the RCC agreed as follows:

50
51 1) Retain the proposal crafted by the sub-committee, as discussed and revised by
52 the RCC;

2) Re-post the proposal in the WESM Market Information Website, highlighting the additional proposed amendments as instructed by the PEM Board for comments of the participants and other interested parties; and

3) To respond to the concerns of the PEM Board as contained in its Memo Directives to the RCC, upon submission of the finalized PR proposal.

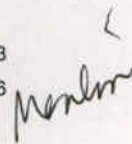
o Proposed Amendments to the WESM Rules and Manual Relative to MRU

NGCP Letter to the PEMC

Mr. Ambrocio R. Rosales discussed the NGCP's letter to PEMC regarding the DOE's directives on the proposed amendments relative to the management of Must Run Units (MRU Manual) and its settlement to be accounted to the Ancillary Services of the System Operator. Mr. Rosales summarized the response of NGCP to the DOE's directives, as follows:

1. The NGCP poses no objection to the recommendation of the DOE except that such proposal shall undergo further and more detailed study and regulatory process before its implementation.
2. Some of the processes that need to be considered in pushing through with the recommendation are as follows:
 - i. Revision of the Philippine Grid Code with a proposal on a new provision on the MRU;
 - ii. Revision of the Ancillary Services Procurement Plan (ASPP) with a proposed method of procurement on MRU; and
 - iii. Proposal for a new procedure and computation of MRU settlement under the Ancillary Services- Cost Recovery Mechanism (AS-CRM).
3. The recommendation being proposed shall undergo public consultation and the ERC's approval.
4. The WESM Technical Committee (TC) shall determine the circumstances wherein MRU is considered part of AS and its causers and beneficiaries as well.
5. Should the settlement of the MRU be accounted as AS, the NGCP's financial exposure would increase since the MRU settlement would be the responsibility of the NGCP.
6. Technically, the MRU is designed as a stop-gap measure to address the system forecasts errors, intra-hour load variation, and supply/energy deficiency.
7. MRU is used by the SO as a real-time solution to maintain system stability and grid security.

In relation to item 4., Mr. Meneses opined that requesting the TC to make a distinction between the types of MRUs that will be called as Ancillary Service is rather contentious. He stated that since the ruling to account the MRU as Ancillary Services of the SO already came from a higher authority than the TC, it may no longer be necessary to request the TC to still perform such. He added that the DOE directive is a plain and simple order without any circumstantial qualification as to when an MRU call can be classified under AS, which means that there is no distinction on the MRU regardless of its application.





1 Mr. Isidro E. Cacho inquired on how long the NGCP can draft the revised ASPP and
2 AS-CRM, if this is the direction that is being required by the DOE directive. Mr.
3 Rosales responded that the current ASPP--which has not considered yet the MRU--
4 is still awaiting the ERC's approval. He added that once the ERC approves the same,
5 the NGCP will submit another set of proposed revisions to include the MRU as
6 Ancillary Service of the NGCP.

7
8 On the part of the DOE, Mr. Binondo stated that the process should be, that once
9 the Philippine Grid Code adopts the MRU, the responsibility of applying or filing with
10 the ERC revisions to the AS-CRM and ASPP relative to MRU shall automatically be
11 given to the NGCP-SO, in order for the MRU to be included in the NGCP's cost as
12 part of its Ancillary Services. He reiterated that the first move is the PGC's adoption
13 of the MRU.

14
15 Mr. Rosales reiterated that the NGCP SO has no objections to the recommendations
16 given by the DOE. However, noting that the directives previously given by the DOE
17 were addressed to the RCC and not to the NGCP, then the NGCP-SO shall await a
18 formal instruction from the DOE directing the NGCP to account the MRU as part of
19 the NGCP's Ancillary Service.

20
21 Mr. Lagarde commented that once the MRU is accounted as part of the SO's
22 Ancillary Service, wherein the Ancillary Service is contracted by the NGCP, even if
23 the same was not utilized, it will still be billed to the Customer as part of the
24 transmission charges. This makes the pass on cost to Customers more expensive
25 unlike when the MRU is billed only when the same is utilized, as in the current set-up.
26 He explained that the difference between the MRU billed in the WESM and billed
27 under the NGCP-SO's Ancillary Service is that if the MRU is made as part of the
28 ASPA, when the same even if the actual energy utilized is below the ASPA level, the
29 pass on cost to the Customer would still be based on the contract. However, if the
30 MRU is in the WESM, only the actual energy usage will be billed. This means that
31 transferring the MRU to the NGCP and accounting it as part of the ASPA makes it
32 more expensive for the Customers, because the NGCP has to maintain the ASPA
33 throughout the contract period.

34
35 Mr. Cacho stated that when the MRU settlement is transferred to the NGCP, we
36 expect the settlement mechanism for the MRU to still be the same. However, it will
37 depend on the ERC's final approval.

38
39 Further to the point raised by Mr. Lagarde, Ms. Joselyn Carabuena stated that under
40 the ASPA, a certain level of capacity is contracted, and whether this capacity is
41 consumed or not, it has to be paid and the cost will only be passed on to the
42 Customer. She then inquired whether a certain level of capacity under the ASPA will
43 be allocated for the MRU, or will a certain capacity level in addition to the regular
44 Ancillary Service be contracted or allocated? She said that in the current set-up, the
45 MRU is called only during emergency, thus, that is the only time that the Customer
46 has to pay for the MRU, unlike when the MRU is included in the ASPA.

47
48 In response to the concerns raised by Mr. Lagarde and Ms. Carabuena, Mr. Meneses
49 stated that their perception regarding the MRU when it is to be accounted for under
50 ASPP is not necessarily true. He explained that the MRU will be transferred as a
51 separate item from the ASPP in the NGCP bill. Thus, it will be reflected as ASPP
52 plus MRU in the NGCP bill. The price or computation, depending on what is
53 approved or will be approved by the ERC, will just be the same whether it is in the



1 WESM or the NGCP bill. The only difference is who will collect--it will now be the
2 NGCP who will collect as part of the transmission charges, instead of PEMC when
3 the same was still part of the WESM bill.

4
5 Dr. Guevara added that even if the MRU is accounted as part of the Ancillary
6 Service, it will not be purchased in the same manner that the ASPA is purchased--
7 through contracting. She emphasized that the MRU will remain as an "on-call"
8 service, which will be paid only when the same is utilized. Further, Dr. Guevara
9 stated that once a sufficient level of Ancillary Service is hit by the NGCP, then the
10 MRU will disappear.

11
12 For clarity, Mr. Binondo explained that the NGCP uses a certain level of Ancillary
13 Service through contracting, which is the ASPA. The mechanism used for the ASPA
14 is the AS-CRM, which has a defined formula approved by the ERC. In the current
15 set-up the NGCP calls the MRU during emergency, but the MRU is settled in the
16 WESM using a formula approved by the ERC. Once the settlement of the MRU is
17 transferred to the NGCP as part of its responsibilities, and assuming the AS-CRM
18 adopts the formula of the MRU, then the settlement of MRU in the WESM and the
19 NGCP will just be the same.

20
21 Mr. Pagobo, for his part, stated that his only concern in the proposal to transfer the
22 MRU settlement to NGCP is the possible increase in the Prudential Requirement
23 which will be required of them by NGCP, since the transmission charges would go up
24 and the Customers' exposure with NGCP would also increase. He expressed that
25 this possible increase which will be triggered by the transfer of MRU settlement with
26 NGCP is what they are trying to avoid. Mr. Meneses responded that in case the MRU
27 settlement will be transferred to the NGCP, the increase in the NGCP bill for the
28 transmission charges and the Prudential Requirement with NGCP will also have a
29 corresponding decrease in the WESM bill and the Prudential Requirement with
30 PEMC. Thus, the amounts will only be transposed.

31
32 Mr. Binondo reiterated that the intention of the DOE's Directives/recommendations is
33 to achieve transparency in prices and address the distortion of actual WESM prices.
34 In case the same formula will be adopted if the MRU settlement is transferred to the
35 NGCP, then the only thing that will change is the administration and procurement of
36 the MRU. He also expressed that when the MRU is transferred to NGCP, it is
37 expected that the NGCP-SO will be able to fully optimize its contracted quantity
38 under its ASPP, which could lead to less MRU calls.

39
40 Mr. Francisco L.R. Castro posed a question from the point of view of an ordinary
41 electricity user, on whether his bill would still be the same once the MRU is
42 transferred from the WESM to the NGCP. Mr. Meneses responded that the
43 household bill would still be the same. Mr. Castro further inquired whether this meant
44 that the formula for MRU and ancillary services are the same. Mr. Meneses
45 responded that they are not. Atty. Tomas explained further that the MRU will become
46 just a component of the NGCP bill and as such, the settlement computation will be
47 modified to now include the formula for the MRU in the transmission charges.

48
49 Mr. Castro asked whether the MRU will be totally eliminated once the NGCP
50 addresses the apparent shortage in its contracted Ancillary Service. Mr. Cacho
51 responded that it can be minimized, but probably not 100% eliminated. At this point,
52 Mr. Castro inquired whether it is possible to request a simulation to show what would
53 be the result in the bill after transferring the MRU settlement from the WESM to the

NGCP. Dr. Guevara noted the suggestion of Mr. Castro, but stated that the simulation might have to be conducted by the ERC and not the RCC since the proposal would be submitted to the ERC. At this point, Dr. Guevara inquired from the ERC whether it is possible for the same to conduct a simulation that would show how much the Consumers would pay if the MRU settlement is with WESM vs. if the same is with the NGCP. Atty. Tomas responded that such simulation is possible to be done by the ERC. He expressed, however, that based on experience, the accuracy of simulations cannot be guaranteed.

At this point, Dr. Guevara thanked Mr. Rosales for discussing with the RCC the content of the NGCP letter.

Proposed Amendments to the WESM Rules and Relevant Manuals

The RCC moved forward with the discussion of the Proposed Amendments to the WESM Rules and relevant Manuals in relation to the MRU.

Discussion Paper

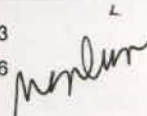
The RCC noted the enhancements made on the discussion paper as submitted by Mr. Rosales. The changes made on the discussion paper can be summarized as follows:

1. In relation to the generators testing their Pmax, the same should not be compensated as MRU but rather, as price taker.
2. Delete local calamities and emergencies and craft corresponding provisions under the Administered Price Methodology Manual.

Dispatch Protocol Manual

Mr. Raymundo discussed the proposed amendments to the Dispatch Protocol Manual, as follows:

Original Provision	Proposed Revision	RCC Discussion/ Revised Proposed Revision
APPENDIX A.5 PRE-DISPATCH MARKET PROJECTION 4.2.8. Security Limits Security Limits are often used to reflect system stability limits and they vary under different system conditions. Security Limits as described in this document covers generator operating limits and transmission branch group limits: <ul style="list-style-type: none"> Generator operating limits (Pmin, Pmax) may vary based on different plant and system conditions. Some generators are required to produce no less than certain amount of output for system reliability reasons. Some 	APPENDIX A.5 PRE-DISPATCH MARKET PROJECTION 4.2.8. Security Limits Security Limits are often used to reflect system stability limits and they vary under different system conditions. Security Limits as described in this document covers generator operating limits and transmission branch group limits: <ul style="list-style-type: none"> Generator operating limits (Pmin, Pmax) may vary based on different plant and system conditions. Some generators are required to produce no less than certain amount of output for system reliability 	





<p>generators are required to restrain their output due to stability considerations. Generating units nominated by the System Operator as a "Must Run Unit" falls in this category. Refer to WESM Criteria for Must Run Units for more details.</p> <ul style="list-style-type: none"> xxxx 	<p>reasons. Some generators are required to restrain their output due to stability considerations. Generating units nominated by the System Operator as a "Must Run Unit" falls in this category. Refer to WESM <u>Criteria and Procedures for Dispatch of Must-Run Units and the Constrain-on or Constrain-off of Generating Units during a Trading Interval Criteria for Must Run Units</u> for more details.</p>	
<p>APPENDIX A.6 REAL TIME DISPATCH SCHEDULE</p> <p>4.2.8. Security Limits Security Limits are often used to reflect system stability limits and they vary under different system conditions. Security Limits as described in this document covers generator operating limits and transmission branch group limits:</p> <ul style="list-style-type: none"> Generator operating limits (Pmin, Pmax) may vary based on different plant and system conditions. Some generators are required to produce no less than certain amount of output for system reliability reasons. Some generators are required to restrain their output due to stability considerations. Generating units nominated by the System Operator as a "Must Run Unit" falls in this category. Refer to WESM Criteria for Must Run Units for more details. xxxx 	<p>APPENDIX A.6 REAL TIME DISPATCH SCHEDULE</p> <p>4.2.8. Security Limits Security Limits are often used to reflect system stability limits and they vary under different system conditions. Security Limits as described in this document covers generator operating limits and transmission branch group limits:</p> <ul style="list-style-type: none"> Generator operating limits (Pmin, Pmax) may vary based on different plant and system conditions. Some generators are required to produce no less than certain amount of output for system reliability reasons. Some generators are required to restrain their output due to stability considerations. Generating units nominated by the System Operator as a "Must Run Unit" falls in this category. Refer to WESM <u>Criteria and Procedures for Dispatch of Must-Run Units and the Constrain-on or Constrain-off of Generating Units during a Trading Interval Criteria for Must Run Units</u> for more details. xxxx 	
<p>APPENDIX A.6 REAL TIME DISPATCH SCHEDULE</p>	<p>APPENDIX A.6 REAL TIME DISPATCH SCHEDULE</p>	<p>Mr. Rosales commented that the term "security limits" should not be used as a generic term even</p>

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<p>4.4. Over-Riding Constraints The MMS provides a functionality that allows the Market Operator to make adjustments in the Operating Constraints of the MDOM for a particular Trading Interval. Such adjustments or overriding constraints in the MDOM is imposed by the Market Operator upon the recommendation of the System Operator through a System Advisory.</p> <p>Imposition of Overriding Constraints in the MDOM include among others the following:</p> <ul style="list-style-type: none"> • Nomination of Must-Run Units (MRU) • Emergency de-rating/outage of specific transmission lines • Additional reserve requirements • Generating unit limitations • Other types as may be recommended by the System Operator 	<p>4.4. Over-Riding Constraints The MMS provides a functionality that allows the Market Operator to make adjustments in the Operating Constraints of the MDOM for a particular Trading Interval. Such adjustments or overriding constraints in the MDOM is imposed by the Market Operator upon the recommendation <u>or submission</u> of the System Operator <u>of security limits, transmission limits and/or contingency list through the MMS-EMS interface facility of the System Operator.</u> a System Advisory.</p> <p>Imposition of Overriding Constraints in the MDOM include among others the following:</p> <ul style="list-style-type: none"> • Nomination of Scheduled Must-Run Units (Scheduled MRU) • Emergency de-rating/outage of specific transmission lines • Additional reserve requirements • Generating unit limitations • Other types as may be recommended by the System Operator 	<p>for "non-security limits."</p> <p>Thus, the RCC agreed to revise the provision, as follows:</p> <p>4.4. Over-Riding Constraints XXX. Such adjustments or overriding constraints in the MDOM is imposed by the Market Operator upon the recommendation of the System Operator. of a System Advisory.</p>
<p>APPENDIX A.7 DISPATCH IMPLEMENTATION</p> <p>4.2.1. Issuance of Dispatch Instructions 4.2.1.1. MW Loading of Trading Participants During normal condition, the MW dispatch of power facilities shall be the Dispatch Schedule for the Trading Interval submitted by the Market Operator. In cases where an infeasible Dispatch Schedule is determined by the Market Operator, a re-dispatch shall be performed by the System Operator, the redispatch schedules shall be communicated to the Trading Participants and correspondingly recorded thru the SO Operator Logs.</p>	<p>APPENDIX A.7 DISPATCH IMPLEMENTATION</p> <p>4.2.1. Issuance of Dispatch Instructions 4.2.1.1. MW Loading of Generating Units, The MW dispatch of generating units shall be the Dispatch Schedule for the Trading Interval submitted by the Market Operator.</p> <p>In cases where an infeasible Dispatch Schedule is determined by the Market Operator, a re-dispatch shall be performed by the System Operator, the redispatch schedules shall be communicated to the affected generating units and correspondingly recorded thru the SO Operator Logs.</p> <p><u>In cases where a system security issue arises during the trading interval and the available Ancillary Services to address the</u></p>	<p>Mr. Raymundo stated that the MW loading is applicable to the generating unit and not the Trading Participant. Mr. Rosales clarified that for aggregated generating units, only one plant operator is given the dispatch instructions. That plant operator shall be responsible in making the adjustments based on the schedule instructed by the SO. The RCC, thus, agreed to revise the proposed revision as follow:</p> <p>4.2.1.1. MW Loading of Trading Participants Generators, The MW dispatch of Generators shall be the Dispatch Schedule for the Trading Interval submitted by the Market Operator.</p> <p><u>In cases where a system security issue arises during the trading interval and the available Ancillary Services to address the security issue/s are exhausted, the System Operator may constrain-on or constrain –off Generators and/or designate Generators as real time MRU. The System Operator shall also appropriately communicate the re-dispatch instructions to the affected generating units and correspondingly recorded thru the SO Operator</u></p>

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	<p><u>security issue or issues are exhausted, the System Operator may constrain-on or constrain-off generating units and/or designate generating units as real time MRU. The System Operator shall also appropriately communicate the re-dispatch instructions to the affected generating units and correspondingly recorded thru the SO Operator Logs.</u></p>	<p><u>Logs.</u></p>
<p>APPENDIX A.7 DISPATCH IMPLEMENTATION 4.3. Compliance With Dispatch Instructions</p> <ul style="list-style-type: none"> The System Operator shall continuously monitor the compliance of trading participants to issued Dispatch Instructions. Any deviation from the issued Dispatch Instructions shall be recorded for purposes of settlement, surveillance, and post audit. Compliance of Ancillary Services Providers to their scheduled dispatch shall be in accordance with the WESM Ancillary Services Compliance Monitoring document. Each registered trading participant shall assure that each of its registered facilities complies with dispatch instructions subject to the provisions of the Grid and Distribution Codes and the WESM Rules Trading Participants shall see to it that their facilities operate within the Dispatch Tolerance limits and standards prescribed by the System Operator. A registered trading participant that expects its registered facility, to operate in a manner that, for any reason, differs materially from the System Operators dispatch instructions shall so notify the System Operator as soon as possible. If failure by a registered facility, to comply with a dispatch instruction and 	<p>APPENDIX A.7 DISPATCH IMPLEMENTATION 4.3. Compliance With Dispatch Instructions</p> <ul style="list-style-type: none"> The System Operator shall continuously monitor the compliance of generating units to issued Dispatch Instructions. Any deviation from the issued Dispatch Instructions shall be recorded for purposes of settlement, surveillance, and post audit. <u>The System Operator shall submit a report containing these information to the Market Operator on a regular basis.</u> Compliance of Ancillary Services Providers to their scheduled dispatch shall be in accordance with the WESM Ancillary Services Compliance Monitoring document. Each registered trading participant shall assure that each of its generating units complies with dispatch instructions subject to the provisions of the Grid and Distribution Codes and the WESM Rules Trading Participants shall see to it that their facilities operate within the Dispatch Tolerance limits and standards prescribed by the WESM Rules. A trading participant that expects its generating unit to operate in a manner that, for any reason, 	<p>Noting the comments in the previous section, the proposal under Appendix A.7 was revised as indicated below. The RCC also agreed to capture both the WESM Rules and the Dispatch Protocol Manual in relation to the provision relating to the Dispatch Tolerance Limits. Thus, the proposed amendments were revised as follows:</p> <p>4.3. Compliance With Dispatch Instructions</p> <ul style="list-style-type: none"> The System Operator shall continuously monitor the compliance of Generators to issued Dispatch Instructions. xxx xxx Each registered trading participant shall assure that each of its Generators complies with dispatch instructions subject to the provisions of the Grid and Distribution Codes and the WESM Rules Trading Participants shall see to it that their facilities operate within the Dispatch Tolerance limits and standards prescribed by the WESM Rules and Manuals. A trading participant that expects its Generators to operate in a manner that, for any reason, differs materially from the System Operator's dispatch instructions shall notify the System Operator as soon as possible. If a Generator fails to comply with a dispatch instruction and endangers electricity system reliability, the System Operator shall declare the Generator to be non-conforming and shall take any actions allowed by the Philippine Grid and Distribution Codes and the WESM Rules.

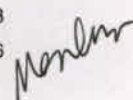
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endangers electricity system reliability, the System Operator shall declare the registered facility to be non-conforming and shall take any actions allowed by the Philippine Grid and Distribution Codes and the WESM Rules.	<p>differs materially from the System Operators dispatch instructions shall so notify the System Operator as soon as possible.</p> <ul style="list-style-type: none"> If a generating unit fails to comply with a dispatch instruction and endangers electricity system reliability, the System Operator shall declare the generating unit to be non-conforming and shall take any actions allowed by the Philippine Grid and Distribution Codes and the WESM Rules. 	
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Management of Excess Generation

Ms. Tanglao presented the proposed changes to the subject Manual. The proposed revisions and highlights of the RCC discussions on the same are summarized in the table below.

Original Provision	Proposed Revision	Remarks
<p>2.0 Definition of Terms</p> <p>2.3 Must Run Units – Generating units which are designated to run during excess generation consistent with the criteria developed by MO and the SO. This is required by the power system for reliability reasons regardless if there is excess generation or not.</p>	<p>2.0 Definition of Terms</p> <p>2.3 <u>Must-Run Unit (MRU) – a generating unit that is not included in the Merit Order Table but identified and instructed by the System Operator (SO) to come on-line, on real-time or scheduled basis, on a particular Trading Interval to augment the Ancillary Services and maintain the System Security and Reliability requirements of the Grid. For clarity, MRU shall be utilized only after the System Operator has exhausted all available Ancillary Services.</u></p> <p>a. <u>Scheduled MRU – MRU designated by the System Operator before the trading interval and included in the RTD schedule through the imposition of Security Limit as defined in the WESM Dispatch Protocol Manual.</u></p> <p>b. <u>Real Time MRU – MRU designated by the System Operator within a trading</u></p>	<p>Harmonize the definition of MRU</p>



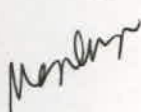
4.0 Criteria and Pre-Conditions for impending and existing Excess Generation	4.0 Criteria and Pre-Conditions for impending and existing Excess Generation	Proposed to be deleted as this may no longer be applicable.
4.2 Cancelled bids and offers for the Real-Time Dispatch are being observed by the Trading Participants unless they are otherwise provided by SO with re-dispatch instructions.	4.2 Cancelled bids and offers for the Real-Time Dispatch are being observed by the Trading Participants unless they are otherwise provided by SO with re-dispatch instructions.	
4.5 The system or regional generation level is approaching the regulating reserve requirement band of the minimum generating limit (Pmin) of the synchronized generators.	4.5 The system <u>frequency has breached the maximum allowable level as provided under the Grid Code</u> of regional generation level is approaching the regulating reserve requirement band of the minimum generating limit (Pmin) of the synchronized generators.	Revise to consider the allowable limits under the Grid Code RCC Discussions: <ul style="list-style-type: none"> Over-frequency is not a technical term.
5.0 Responsibilities Pertaining to the Mitigation and Arrest of Excess Generation in the Power System		
5.1.2 Coordinate with MO and provide necessary information which will be utilized in the calculation of the dispatch schedule to mitigate or arrest possible excess generation condition indicated in the market projections.	5.1.2 Coordinate with MO and provide necessary information, <u>including but not limited to updated planned outage schedules of generating units</u> , which will be utilized in the calculation of the dispatch schedule to mitigate or arrest possible excess generation condition indicated in the market projections.	To reiterate the provision of updated outage schedule, if any.
5.1.3 Elect reliability must-run units based on the Dispatch Criteria on Must Run Units approved by the PEM Board.	5.1.3 <u>Nominate</u> Elect reliability must-run units based on the <u>Criteria and Procedures for Dispatch of Must-Run Units and the Constrain-on or Constrain-off of Generating Units during a Trading Interval</u> Dispatch Criteria on Must Run Units approved by the PEM Board	Harmonization

As an additional comment, Mr. Rosales stated that management of excess generation when scheduling is involved, should be a responsibility of the Market Operator, and when real-time is involved, should be the responsibility of the System Operator. He inquired from the MO on what criteria is being used to address excess generation during scheduling, such as in cases where the need to shut down some generators are required. Dr. Guevara instructed the MO and SO representatives to discuss the concern of Mr. Rosales. Mr. Rosales then stated that he will submit his comments on the same to the sub-group on the Management of Excess Generation.

System Security and Reliability

Mr. Rosales discussed the proposed revisions in the Manual on System Security and Reliability Guidelines. The proposed revisions and highlights of the RCC discussions on the matter are summarized in the following table.

Original Provision	Proposed Revision	Remarks
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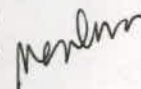




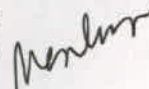
2. DEFINITION OF TERMS		
<p>Include the definition of Must Run Unit (MRU) as approved by the RCC board.</p> <p>Include the definition of Must Stop Unit (MSU) as approved by the RCC Board.</p>	<p>Must-Run Unit (MRU) – a generating unit identified and instructed by the System Operator (SO) to come on-line, on real-time or scheduled basis on a particular Trading Interval but the dispatch is said to be Out of Merit to augment the Ancillary Services and maintain the System Security requirements of the Grid. For clarity, MRU shall be utilized only after the System Operator has exhausted all available Ancillary Services.</p> <p>Must-Stop Unit (MSU) – a generating unit identified and instructed by the System Operator to reduce the provision of energy due to its non-compliance of the Dispatch Schedule to address or prevent possible threat to the System Security requirements of the Grid.</p>	
<p>Include the definition of Security Limits as defined in the WESM Rules</p>	<p>Security Limits –reflect system stability limits imposed on the output of generating units whenever there are constraints in the grid (i.e. generator operating limits and transmission branch group limits), as defined in the WESM Dispatch Protocol Manual, and which may vary under different system conditions.</p>	
<p>Include the definition of Out-of Merit Dispatch as defined in the WESM Rules.</p>	<p>Out of Merit Dispatch – the dispatch of a generating unit outside or not in accordance with the WESM Merit Order Table to address threats in System Security.</p>	
<p>Include the definition of Constrain-on as defined in the WESM rules</p>	<p>Constrain-on. In respect of a <i>generating unit</i>, the output of that <i>generating unit</i> is limited above the level to which it would otherwise have been dispatched by the <i>Market Operator</i> on the basis of its <i>energy offer</i>.</p>	
<p>Include the definition of Constraint as defined in the WESM rules</p>	<p>Constraint. A limitation on the capability of any combination of <i>network elements, loads, generating units or Ancillary Service Providers</i> such that it is, or is deemed by the <i>System operator</i> to be, unacceptable to adopt the pattern of transfer, consumption, generation or production of electrical power or other services that would be most desirable if the limitation were removed.</p>	
<p>Include the definition of Intervention as defined in the WESM rules.</p>	<p>Intervention. A measure taken by the <i>System Operator</i> when the <i>grid</i> is in the <u>emergency state</u> condition as established in the <i>Grid Code</i> arising from a threat to <i>system security, force majeure or emergency brought about by multiple tripping of lines/equipment</i>. During such event, the <i>administered price cap</i> shall be used for settlements.</p>	
<p>Backup reserve (also known as cold standby reserve) refers to a generating unit that has fast start capability and can synchronize with the grid to provide its declared capacity for a minimum period of eight (8) hours.</p>	<p>Also called Dispatchable Reserve (DR)</p>	<p>To align the definition with the Ancillary Service Procurement Plan (ASPP)</p>

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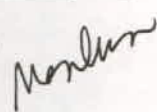
<p>Contingency reserve is the generating capacity that is intended to take care of the loss of the largest synchronized generating unit or the power import from a single grid interconnection, whichever is larger. Contingency reserve includes spinning reserve and backup reserve.</p>	<p>Same definition as Spinning Reserve.. A Generating Unit providing Spinning Reserve Contingency reserve as an Ancillary Service shall be Synchronized with the Grid and be available to automatically respond (i.e. free-governor or AGC mode)when the grid frequency breached the 59.7 Hz as a result of any sudden loss or significant reduction in generating capacityorhigh intra-hour variations in system demand that would lead the regulating reserve to be depleted.</p>	<p>To align the definition with the Ancillary Service Procurement Plan (ASPP)</p>
<p>Operating margin is the margin of generation over the total demand plus losses that is necessary for ensuring power quality and the security of the grid. Operating margin is the sum of the load following and frequency regulating reserve and the contingency reserve.</p>	<p>As defined in the PGC: Operating Margin. The available generating capacity in excess of the sum of the system demand plus losses within a specified period of time which include Ancillary Service such as Regulating, Contingency and Dispatchable reserves. This is also called the Gross Operating reserve.</p>	<p>To specify clearly the definition of Operating Margin which includes the Ancillary Service reserves.</p>
<p>New definition. Include in the definition the Net Operating Margin</p>	<p>Net Operating Margin is equal to the Operating Margin less the capacity of the Regulating reserve. This is also called the Net Operating Reserve.</p>	<p>The "net" operating margin shall be used as reference by the System Operator in determining the condition of the power system operating state. Take note that the capacity of the regulating reserve was not included to allow frequency regulation even during emergency conditions.</p>
<p>Red Alert. An alert issued by the System Operator when the Grid Contingency Reserve is zero, a generation deficiency exists, or there is Critical Loading or Imminent Overloading of transmission lines or Equipment.</p>	<p>Red Alert. An alert notice issued by the system Operator when the Grid Contingency ReserveNet Operating Reserve is zero or at its critical level (i.e. less than 1% of System Demand) or a generation deficiency exists, or there is Critical Loading or Imminent Overloading of transmission lines or Equipment.</p>	<p>To emphasize clearly the type of warning notice issued by the system operator whenever the operating condition is in the Emergency state.</p> <p>RCC Discussions:</p> <p>The RCC agreed to revise the proposal, noting that when the term critical level is included in the wordings of the provisions, it should be followed by a value that would qualify under critical level. The revised proposal should then read as follows:</p> <p>Red Alert. An alert notice issued by the System Operator when the Grid Contingency ReserveNet Operating Reserve is zero or a generation deficiency exists, or there is Critical Loading or Imminent Overloading of transmission lines or Equipment.</p>
<p>Spinning Reserve. A synchronized generating capacity from Qualified Generating Units allocated to cover loss of a synchronized generating unit or the power import from single-circuit interconnection, whichever is larger.</p>	<p>Also known as Contingency Reserve</p>	<p>To align the definition with the Ancillary Service Procurement Plan (ASPP)</p>
<p>Voltage Control. Any actions undertaken by the System Operator or User to maintain</p>	<p>Voltage Control. Any actions undertaken by the System Operator or User to maintain the voltage of the Grid within the limits prescribed by the Grid Code such</p>	<p>This is to include the provision of MRU allocation when used by the System Operator as reactive support to satisfy voltage</p>



the voltage of the Grid within the limits prescribed by the Grid Code such as, but not limited to, adjustment of generator reactive output, adjustment in transformer taps or switching of capacitors or reactors.	as, but not limited to, adjustment of generator reactive output, adjustment in transformer taps or switching of capacitors or reactors. Also, the System Operator may schedule and make use of Must Run Unit (MRU) in order to further provide reactive support to the system.	requirement as specified in the MRU criteria. The RCC agreed to revise the provision, as follows: Voltage Control. Any actions undertaken by the System Operator or User to maintain the voltage of the Grid within the limits prescribed by the Grid Code such as, but not limited to, adjustment of generator reactive output, adjustment in transformer taps or switching of capacitors or reactors.
Yellow Alert. A notice issued by the System Operator when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher.	Yellow Alert Notice. A notice issued by the System Operator when the Contingency Reserve Net Operating Margin is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher.	To clearly specify when to issue Yellow Alert Notice using the Net Operating margin as reference when it is less than the largest synchronized generating unit.
Inclusion of the PGC definition with provision - Weather Disturbance Alert	Weather Disturbance Alert Notice (WDAN) is an alert notice issued by the System Operator when a weather disturbance has entered the Philippine area of responsibility.	The system is in the Alert State when the System Operator issued WDAN provided the path of the weather disturbance is already established and will pose threat to the grid operations.
Inclusion of the PGC definition with provision - Blue Alert	Blue Alert Notice is issued by the System Operator when a tropical weather disturbance is expected to make a landfall within 24 hours;	The issuance of Blue Alert Notice by the System Operator would clearly emphasize the imminent threat in the security and reliability of the grid.
5.1 Normal State Operation The grid shall be operated so that it remains in the normal state, i.e.: a. The operating margin is sufficient; b. System frequency is within the limits of 59.7 and 60.3 Hz; c. Voltages at all connection points are within the limits of 0.95 and 1.05 of the nominal value; d. The loading levels of all transmission lines and transformers are below 90% of their continuous ratings; e. The grid configuration is such that any potential fault current can be interrupted and the faulted equipment can be isolated from the grid; and	5.1 Normal State Operation The grid shall be operated so that it remains in the normal state, i.e.: a. The Net Operating Margin is sufficient; b. System frequency is within the limits of the normal range of 59.4Hz and 60.6Hz. However, to ensure power quality frequency, the grid frequency shall be operated within the 59.7 and 60.3 Hz; c. Voltages at all connection points are within the limits of 0.95 and 1.05 of the nominal value; d. The loading levels of all transmission lines and transformers are below 90%100% of their continuous ratings; e. The grid configuration is such that any potential fault current can be interrupted and the faulted equipment can be isolated from the grid; and f. The static and dynamic stability of the power system is maintained.	To clearly specify the conditions that would qualify the condition of the power system when operating in the normal state.



<p>f. The static and dynamic stability of the power system is maintained.</p>		
<p>As stated in the PGC: Grid shall be considered to be in the Alert State when any one of the following conditions exists:</p> <ul style="list-style-type: none"> a) The Grid Contingency Reserve is less than the capability of the largest Synchronized Generating Unit or the power import from single Grid interconnection, whichever is higher; b) The voltages at the Connection Points are outside the limits of 0.95 and 1.05 but within the limits of 0.90 and 1.10 of the nominal value; c) There is Critical Loading or Imminent Overloading of transmission lines or substation Equipment; d) A weather disturbance has entered the Philippine area of responsibility, which may affect Grid operations; or e) Peace and order problems exist, which may pose a threat to Grid operations. 	<p>5.2 Grid shall be considered to be in the Alert State when any one of the following conditions exists:</p> <ul style="list-style-type: none"> a) The Grid Contingency Net Operating Margin Reserve is less than the capability of the largest Synchronized Generating Unit or the power import from a single Grid interconnection, whichever is higher; b) The voltages at the Connection Points are outside the limits of 0.95 and 1.05 but within the limits of 0.90 and 1.10 of the nominal value; c) There is Critical Loading or Imminent Overloading of transmission lines or substation Equipment; d) A weather disturbance has entered the Philippine area of responsibility, which may affect Grid operations; e) A Blue Alert Notice is issued by the System Operator if the weather disturbance is to make landfall within 24 hours; and f) Peace and order problems exist, which may pose a threat to Grid operations. 	<p>To clearly specify the conditions that would qualify the condition of the power system when operating in the Alert state.</p>
<p>As stated in the PGC: The Grid shall be considered to be in the Emergency State when a Multiple Outage Contingency has occurred without resulting in Total System Blackout, and any one of the following conditions exists:</p> <ul style="list-style-type: none"> a) There is generation 	<p>5.3 The Grid shall be considered to be in the Emergency State when a Multiple Outage Contingency has occurred without resulting in Total System Blackout when any one of the following conditions exists:</p> <ul style="list-style-type: none"> a) The Net Operating Margin is critical (i.e. less than 1% of the system demand) or zero (0); b) Generation deficiency exists; c) Grid transmission voltages are outside the 	<p>To clearly specify the conditions that would qualify the condition of the power system when operating in the Emergency state. It can be noted that an equivalent of 1% instead of 4% of the system demand was allocated for RR since this would clearly emphasize that the net operating margin is already at its critical level.</p>



<p>deficiency;</p> <p>b) Grid transmission voltages are outside the limits of 0.90 and 1.10; or</p> <p>c) The loading level of any transmission line or substation Equipment is above 110% of its continuous rating.</p>	<p>limits of 0.90 and 1.10;</p> <p>d) The Grid Frequency are outside the limits of 59.4Hz and 60.6Hz; and</p> <p>e) The loading level of any transmission line or substation Equipment is above 110% of its continuous rating.</p>	<p>Based on RCC discussion, the proposal was revised as follows:</p> <p>5.3 The Grid shall be considered to be in the Emergency State when a Multiple Outage Contingency has occurred without resulting in Total System Blackout or-when any one of the following conditions exists:</p> <p>XXX</p>
<p>5.2 Single Outage (N-1) Contingency Criterion</p> <p>The security and reliability of the grid shall be based on the single outage contingency (N-1) criterion. This criterion specifies that the grid shall continue to operate in the normal state following the loss of one generating unit, transmission line, or transformer.</p> <p>5.3 Voltage and Reactive Power Control</p>	<p>5.4 Single Outage (N-1) Contingency Criterion</p> <p>The Security and Reliability of the Grid shall be based on the Single Outage Contingency criterion. This criterion specifies that the Grid shall continue to operate in the Normal State following the loss of one Generating Unit, transmission line, or transformer. <u>However, the System Operator shall take the necessary actions whenever there's already a threat or an impending threat in system security as a result of non-compliance to single outage contingency criterion, through constrain-on/constrain-off of generating units or the use of MRUs if Contingency Reserves and/or Dispatchable Reserves are not applicable, to ensure the security and reliability of the grid.</u></p> <p>5.4 Voltage and Reactive Power Control</p> <p>h. <u>The System Operator is responsible for controlling Grid Voltage Variations during emergency conditions through a combination of direct control and timely instructions to Generators and other Grid Users,</u> ensuring the Grid Voltage is maintained within the normal limits at all times and shall take the necessary actions to the best its judgement whenever the grid voltage of +/- 5% of the nominal voltage are breached and even during emergency conditions through a combination of direct control and timely use of MRUs as required by the System Operator.</p>	<p>To incorporate the use of MRU and the instruction of the System Operator to constrain-on and constrain-off to address compliance of single outage contingency criterion</p> <p>This is to include the provision of MRU allocation when used by the System Operator as reactive support to satisfy voltage requirement as specified in the MRU criteria.</p>
<p>5.4 Frequency Control</p> <p>a. The system frequency shall be controlled by the frequency regulating and load following reserve during normal conditions, and by the timely use of spinning reserve, backup reserve, automatic load dropping (ALD) and/or manual load dropping (MLD) during emergency conditions.</p> <p>b. The load following and frequency regulating reserve shall include the primary response and secondary response of generating units.</p>	<p>5.5 Frequency Control</p> <p>a. The system frequency shall be controlled by automatic responses of the frequency regulating and contingency reserves and load following reserve during normal conditions, and by the timely use of spinning dispatchable reserve to maintain the grid in the Normal operating state. Also, the System Operator shall constrain-on or constrain-off and may make use of MRUs whenever the grid frequency breached the 59.7Hz and 60.3Hz. However, activation of the backup reserve, automatic load dropping (ALD) scheme and/or implementation of manual load dropping (MLD) during emergency conditions would take place to protect the integrity of the grid whenever problem on supply capacity will occur as a result of generator tripping or generation deficiency exists.</p>	<p>As approved by RCC in compliance to DOE's directives for submission to GMC on PGC amendments.</p> <p>The RCC revised the provision as follows:</p> <p>5.5 Frequency Control</p> <p>a. The system frequency shall be controlled by automatic responses of the frequency regulating and contingency reserves and load following reserve during normal conditions, and by the timely use of spinning dispatchable reserve to maintain the grid in the Normal operating state. Also, the System Operator shall constrain-on or constrain-off and may</p>





<p>c. A generating unit providing primary response for frequency regulation as an ancillary service shall operate in an automatic frequency-sensitive mode (also known as free-governor mode) for automatic response of the units power output to changes in frequency. The speed-governing system of the generating unit shall have a maximum response time of five (5) seconds.</p> <p>d. Secondary response shall be required from selected generating units providing ancillary services for frequency regulation. Frequency control using the secondary response of the generating units shall be accomplished through Automatic Generation Control (AGC) or manual adjustment of generation with specific dispatch instructions from the System Operator. The maximum response time for the change in the units power output shall be 25 seconds and which shall be sustainable for at least 30 minutes.</p> <p>g. Generating unit providing spinning reserve as an ancillary service shall be synchronized with the grid and be available to automatically respond to any sudden loss or significant reduction in generating capacity.</p> <p>h. A generating unit providing backup reserve shall have fast</p>	<p>b. The load following and frequency regulating reserve shall include the primary response and secondary response of generating units. (For deletion)</p> <p>c. The Generating Unit providing Primary Response for Frequency regulation as an Ancillary Service shall operate in an automatic Frequency-sensitive mode (also known as free-governor mode) for automatic response of the Unit's power output to changes in Frequency.</p> <p>d. The generating unit providing Secondary Response for Frequency Regulation as an Ancillary Service shall operate in an Automatic Generation Control (AGC) for automatic response of the Unit's power output to changes in frequency. The generating unit shall adjust its generating output accordingly based on the frequency deviation in order to restore back the frequency within the desired dead band.</p> <p>g. Generating unit providing spinning reserve contingency reserve shall be Synchronized with the Grid and be available to automatically respond (i.e. free-governor or AGC mode) when the grid frequency breached the 59.7 Hz as a result of any sudden loss or significant reduction in generating capacity or high intra-hour variations in system demand that would lead the regulating reserve to be depleted.</p> <p>h. A generating unit providing backup dispatchable reserve shall have fast start capability to synchronize to the grid within fifteen (15) minutes and its capacity shall be sustainable for a minimum period of eight (8) hours.</p>	<p>make use of MRUs whenever the grid frequency breached the 59.7Hz and 60.3Hz. However, activation of the backup reserve, automatic load dropping (ALD) and/or implementation of manual load dropping (MLD) during emergency conditions would take place to protect the integrity of the grid whenever supply capacity is insufficient as a result of generator tripping or generation deficiency exists.</p> <p>b. The Generating Unit providing Primary Response for Frequency regulation as an Ancillary Service shall operate in an automatic Frequency-sensitive mode (also known as free-governor mode) for automatic response of the Unit's power output to changes in Frequency. The speed-governing system of the generating unit shall have a maximum response time of five (5) seconds.</p> <p>c. The generating unit providing Secondary Response for Frequency Regulation as an Ancillary Service shall operate in an Automatic Generation Control (AGC) for automatic response of the Unit's power output to changes in frequency. The generating unit shall adjust its generating output accordingly based on the frequency deviation in order to restore back the frequency within the desired dead band. The maximum response time for the change in the units power output shall be 25 seconds and which shall be sustainable for at least 30 minutes.</p> <p>xxx</p>
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monline

start capability and its capacity shall be sustainable for a minimum period of eight (8) hours.		
5.5 System Reserve Requirements	5.6 System Reserve Requirements	
<p>The operating margin of the grid shall include the generating capacity for the load following and frequency regulating (LFFR) reserve, which is required to respond to changes in demand during normal conditions and the contingency reserve needed to respond to a sudden reduction in generation during emergency conditions.</p> <p>c. The required system reserves shall be at least equal to:</p> <p>☐ Spinning Reserve, % = $\frac{\text{Capacity of Largest Generating Unit On Line}}{\text{System Peak Demand}} \times 100$</p> <p>☐ Load Following and Frequency Regulating Reserve (LFFR), % = $\frac{\text{Average Load Forecast Variance (4\% in Luzon)}}{\text{System Peak Demand}} \times 100$</p> <p>☐ Backup Reserve, % = $\frac{\text{System Planning Reserve} - \text{Spinning Reserve}}{\text{System Peak Demand}} \times 100$ where System Planning Reserve = Loss-of-Load Probability (LOLP) for one year</p>	<p>The operating margin is the available generating capacity in excess of the sum of the system demand which include Ancillary Service such as Regulating, Contingency and Dispatchable reserves.</p> <p>c. The required system reserves shall be as follows:</p> <ul style="list-style-type: none"> • Regulating Reserve (RR) = the level of reserve requirement for this type of ancillary service shall be scheduled on an hourly basis and shall be based on the latest Ancillary Service Procurement Plan (ASPP) as approved by ERC. • Contingency Reserve (CR) = the level of reserve requirement for this type of ancillary service shall be scheduled on an hourly basis which shall be based on the latest Ancillary Service Procurement Plan (ASPP) as approved by the ERC. • Dispatchable Reserve (DR) = the level of reserve requirement and the manner of its scheduling for this type of ancillary service shall be based on the latest Ancillary Service Procurement Plan (ASPP) as approved by the ERC. 	

1
2 Mr. Meneses inquired whether it is possible to introduce another qualifier for the N-1
3 criterion such that the system cannot be operated in N-2 condition, as such results in
4 Manual Load Dropping. Dr. Guevara stated that the Grid Code does not state that N
5 is variable. Mr. Rosales stated that what is provided under the Grid Code is the
6 Single Outage Criterion. Dr. Guevara responded that such provision does not state
7 that N is variable at all times. She expressed that the RCC needs to figure out if there
8 is a need to state in the Grid Code that N is variable. Mr. Rosales opined that since N
9 is not defined in the Grid Code, then there is no need to define it in the Manual.
10 Noting that the matter cannot be immediately resolved at the RCC level, Mr. Cacho
11 suggested to wait for the GMC's approval of the Grid Code.

12
13 At the end of the discussion on the matter, the RCC summarized the Manuals that
14 need to be finalized relative to the MRU proposal, as follows:

- 15
16 1. Management of Excess Generation
17 2. MRU Manual
18 2. Dispatch Protocol Manual
19 4. Administered Price Determination Methodology
20 5. System Security and Reliability
21





The RCC agreed to continue with the discussion on the matter and the Manuals for revision in the next meeting scheduled in December 2013.

o Proposed Amendment to WESM Rules and PEN Manual

Mr. Marcial Jimenez presented the revised proposal following the RCC discussions on the matter during the previous meeting, with the following highlights:

Proposed Amendments to WESM Rules Section 3.10.5

Consideration of PSM and Local PEN

Original	Proposed
In the event XXX	In the event XXX
(a) The Market Operator may, as soon as possible after the end of a trading interval, issue a pricing error notice, in which case, the ex-post quantities and the ex post prices determined according to clause 3.10.7 shall also serve as ex-ante quantities and ex-ante prices.	(a) The Market Operator may, <u>as soon as possible after the end of a trading interval</u> , issue a pricing error notice, in which case, the ex-post quantities and the ex post prices determined according to clause 3.10.7 shall also serve as ex-ante quantities and ex-ante prices.
Original	Proposed
Continuing.. XXX	Continuing.. XXX
If no ex-post prices can be determined or the calculated prices are believed to be in error as a result of the imposition or relaxation of constraints pursuant to clause 3.5.13.1, the Market Operator shall re-run the Market Dispatch Optimization Model.	If no ex-post prices can be determined or the calculated prices are believed to be in error as a result of the imposition <u>or relaxation</u> of constraints pursuant to clause 3.5.13.1, the Market Operator shall re-run the Market Dispatch Optimization Model. <u>However, if the pricing error is due to the occurrence of a constraint violation on load-end equipment in the Market Network Model, or if the pricing error is due to network congestion resulting in extreme nodal price separations, the Market Operator shall apply price substitution mechanisms to determine the appropriate ex-ante or ex-post price.</u>
Original	Proposed
Continuing.. XXX	Continuing.. XXX
The Market Operator shall develop and publish the procedures for the determination of the market re-run prices. Such procedures shall provide the criteria and conditions for the market re-run and the timetable for implementation.	The Market Operator, <u>in consultation with the WESM Members and subject to the approval of the PEM Board, ERC, and DOE</u> , shall <u>develop and</u> publish the procedures for the determination of the market re-run prices <u>and substitute prices</u> . Such procedures shall provide the criteria and conditions for the market re-run and <u>the application of substitute prices including</u> the timetable for implementation.
Original	Proposed
(b) If no pricing error notice is issued within the time specified in the foregoing paragraph, the ex-post prices and quantities shall serve as ex-ante prices and quantities and shall stand irrespective of the outcome of any subsequent investigations or resolutions of any dispute.	(b) <u>If a pricing error is determined but no pricing error notice is issued within the time specified in the foregoing paragraph, the Market Operator shall issue the pricing error notice prior to the issuance of the preliminary settlement for the relevant billing period.</u> The ex-post prices and quantities shall serve as ex-ante prices and quantities and shall stand irrespective of the outcome of any subsequent investigations or resolutions of any dispute.
(c) Should the pricing error also include reserves, the reserve quantity and price determined in the ex-post run shall serve as the reserve quantity and prices.	(c) Should the pricing error also include reserves, the reserve quantity and price determined in the ex-post run shall serve as the reserve quantity and prices.

Proposed Amendments to PEN Manual

Manila



Categories of Pricing Error

Original	Proposed	Reason
5.1.2. Non-congestion pricing errors are those that occur when there are no ex-ante prices or ex-post prices are determined or communicated within the timetable or when such prices are determined to be in error but are otherwise not classified as network congestion pricing errors under the PSM Manual.	5.1.2. Non-congestion pricing errors are those that occur when there are no ex-ante prices or ex-post prices <u>are</u> determined or communicated within the timetable or when such prices are determined to be in error but are otherwise not classified as network congestion pricing errors under the PSM Manual. <u>Non-congestion pricing errors may also include localized non-congestion at the load-end substations.</u>	Clarification that non congestion pricing errors may include localized non-congestion at the load-end substations.
6.1.1 XXX For avoidance of doubt, only constraint violation coefficients associated with localized base case, contingency and transmission constraint group constraints are considered as non-congestion pricing errors. Localized constraint refers to constraint that manifests on a radially-connected line or load end transformer, which is the source of the load connected to it, or step-up transformer in a generating plant.	6.1.1 XXX For avoidance of doubt, only constraint violation coefficients associated with localized base case, contingency and transmission constraint group constraints are considered as <u>localized</u> non-congestion pricing errors. Localized constraint refers to constraint that manifests on a radially-connected line or load end transformer, which is the source of the load connected to it, <u>or step-up transformer in a generating plant.</u>	<u>Definition of Localized Constraint</u>

Definition of Local Non-Congestion P E

Original	Proposed	Reason
New Provision	<u>6.1.5 The case when the transmission limit of the load end equipment in the Market Network Model are violated shall be defined as a Localized Non-Congestion Pricing Error.</u> A Localized Non-Congestion Pricing Error shall be defined as the case when the <u>load end equipment in the Market Network Model exceeds its transmission limit</u>	Since the increase in PEN issuances from load end transformer contingency violations, there is a need to modify the methodology of identifying PENs
Original	Proposed	Reason
New	<u>8.1.4 Where the pricing error is a Localized Non-Congestion Pricing Error as defined in Section 6.1.5 of this Manual, the substitute ex-ante or ex-post prices or Locational Marginal Price (LMP) for the identified nodes with such pricing errors will be determined by the formula as follows:</u>	The RCC agreed to adopt the use of percentage weight of LMP of 5 nearest customer nodes as the substitute price, based on the results of the simulation.

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Local PEN Determination of Prices

Original	Proposed	Reason
	<p><u>LMP_i = percentage weight of LMP of 5 nearest customer nodes where the 5 nearest customer nodes are defined to be the nodes with the nearest absolute difference with respect to the affected node and selected as follows:</u></p> <p><u>= the lowest transmission loss factor to the affected nodes</u></p> $D(i, A) = \text{ABS} \left[\frac{1}{TLF_i} - \frac{1}{TLF_A} \right]$	

Original	Proposed	Reason
	<p><u>Where,</u></p> <p><u>TLF_i = Transmission Loss Factor of node i where i refers to customers not affected by load-end contingency CVCs</u></p> <p><u>TLF_A = Transmission Loss Factor of node A where A refers to the affected node</u></p> <p><u>The ex-ante or ex-post price and schedule for the nodes not affected by the pricing error shall be valid.</u></p> $D(i, A) = \text{ABS} \left[\frac{1}{TLF_i} - \frac{1}{TLF_A} \right]$	

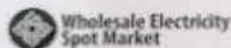
Original	Proposed	Reason
8.3.2 If the ex-ante market run indicates the simultaneous occurrence of congestion pricing error and non-congestion pricing error, such that the resulting prices reflect constraint violation coefficients ("CVC") or there are no valid prices, WESM Rules clauses 3.10.5 (a) and (b) shall apply. As such, the ex-post prices, if valid, shall serve as ex-ante prices.	8.3.2 If the ex-ante market run indicates the simultaneous occurrence of <u>non-congestion pricing error in combination with non-congestion pricing error and/or Localized Non-Congestion Pricing Error as defined in Section 6.1.5 of this manual</u> , such that the resulting prices reflect constraint violation coefficients ("CVC") or there are no valid prices, WESM Rules clauses 3.10.5 (a) and (b) shall apply. As such, the ex-post prices, if valid, shall serve as ex-ante prices	Priority of Non-Congestion Pricing Error as this includes bad data, system supply and demand conditions, etc.

Simultaneous Occurrence of Pricing Errors

Original	Proposed	Reason
New	<p><u>8.3.6 If the ex-ante or ex-post market run indicates the simultaneous occurrence of congestion pricing error and Localized Non-Congestion Pricing Error as defined in Section 6.1.5 of this manual, such that there are no valid prices, PSM Manual shall be applied by using the substitute prices in accordance to Section 8.1.4,</u></p>	Priority of PSM over Local PEN since PSM affects the whole region/system instead of a single node.

Simultaneous Occurrence of Pricing Errors

Non-Congestion	Congestion	Local PEN	Action/Final Declaration
PEN	PSM	LNP	
X	X	X	PEN
X	X		PEN
X		X	PEN
	X	X	PSM
X			PEN
	X		PSM
		X	LNP
			OK



Following the presentation, the RCC approved the posting of the proposed amendments to the WESM Rules and PEN Manual for comments of participants and interested parties.

4. New Business

- o Proposed Amendments to various WESM Manuals

Dr. Guevara noted that the RCC has not yet been given copies of the proposal for amendments to the subject Manuals, and that the presentations are being made to request for the RCC's approval for posting of said amendments in the WESM website to solicit comments of participants and interested parties. The RCC requested to be given copy of the proposals upon receipt of the same by the Secretariat.

Proposed Amendments to the Manual on the Methodology for Determining Pricing Errors and Price Substitution Due to Congestion for Energy Transactions in the WESM

Mr. Jimenez presented the proposed amendments to the Manual on Methodology for Determining Pricing Errors and Price Substitution Due to Congestion for Energy Transactions in the WESM. The proposed amendments are aligned with the recommendations of the auditor to further improve the documents, especially with regard to compliance, context, and accountability. Below are the major changes being proposed by PEMC on the Manual.





Major Changes to the Market Manual

Description of Change	Highlights
New Structure for Market Manuals	Implementation of new guidelines for writing Market Manuals, which includes prescribed formats and guidelines for content
Compliance	✓ Scored 3 because there is an inconsistency between the WESM Rules 3.13 (Settlement quantities) and this Procedure. ✓ TWG will submit proposed amendments to the WESM Rules in this regard.
Context	□ Added references: ✓ Criteria and Guidelines for the Issuance of Pricing Error Notices and Conducting Market Reruns* ✓ PEN & MRR manual
Accountability	Explicitly stated the responsibility of MO in maintaining and implementing the PSM methodology.



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Major Changes to the Market Manual

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New Structure for Market Manuals	Implementation of new guidelines for writing Market Manuals, which includes prescribed formats and guidelines for content
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Context	□ Added references: ✓ Criteria and Guidelines for the Issuance of Pricing Error Notices and Conducting Market Reruns* ✓ PEN & MRR manual
Accountability	Explicitly stated the responsibility of MO in maintaining and implementing the PSM methodology.



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Proposed Amendments

Title	Current Provision	Proposed Amendment
Issuance and Publication of Pricing Error Notices and Substitute Prices	<p>From Section 9 to Section 4.4</p> <p>9.1 Immediately after each trading interval when the pricing error occurs, as defined in this Manual, the Market Operator will issue pricing error notices (congestion or non-congestion related pricing errors) to the Trading Participants by electronic means. Where no pricing error notice is issued within the timetable, the Market Operator shall issue the pricing error notice prior to the issuance of the preliminary settlement statement for the relevant billing period. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p> <p>9.2 All Trading Participants shall be notified of the generator substitute prices and the estimated average load prices within the next trading interval after the end of the trading interval when the pricing error occurs. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p> <p>9.3 Within two (2) business days after the trading day when the pricing error occurs, the Market Operator shall publish in the market information website a summary of the pricing error notices issued for that trading day pursuant to this Manual, as well as the corresponding substitute prices. The publication of all relevant information will be in accordance with the relevant provisions of the WESM Rules and relevant market manuals. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p>	<p>4.4.1 The issuance and publication of pricing error notices, substitute prices, and estimated average load prices, as defined in this Manual shall be:</p> <p>Immediately after each trading interval when the pricing error occurs, through the Market Information Website or, as defined in the Manual, the Market Operator will issue pricing error notices (congestion or non-congestion related pricing errors) to the Trading Participants by electronic means. Where no pricing error notice is issued within the timetable, the Market Operator shall issue the pricing error notice prior to the issuance of the preliminary settlement statement for the relevant billing period. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p> <p>9.2 All Trading Participants shall be notified of the generator substitute prices and the estimated average load prices within the next trading interval after the end of the trading interval when the pricing error occurs. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p> <p>9.3 Within two (2) business days after the trading day when the pricing error occurs, verification of the Market Operator shall publish in the market information website, through a summary of the pricing error notices issued for that trading day pursuant to the Manual, as well as the corresponding substitute prices. The publication of all relevant information will be in accordance with the relevant provisions of the WESM Rules and relevant market manuals. (As approved by PEM Board Resolution No. 2010-73 dated 27 October 2010)</p> <p>C) Prior to the issuance of the preliminary settlement statement for the relevant billing period, after the final validation of the Market Operator.</p>



Wholesale Electricity
Spot Market

Pending Issue: Changes to WESM Rule 3.13 re Settlement Quantities need to be approved by DOE

Summary of Activities	Remarks
PEMC proposed changes on the WESM Rules on the pricing errors related to congestion	Approved by the PEM Board together with this manual as urgent amendments on 27 August 2008
Department of Energy (DoE) endorsed this manual for approval of the ERC.	ERC approved the methodology subject to some modifications
PEMC has revised the manual following ERC's decision and order on ERC Case NO. 2008 -051 RC dated 16 February 2009 and 17 August 2009.	ERC granted provisional approval on said changes on its decision on 14 February 2011.
This manual was again revised on 12 November 2010 to clarify the manner of computation for regional pricing during events of network congestion	However, to ensure consistency of this Manual to the WESM Rules, PEM Board approved changes to WESM Rules 3.13 must be approved and promulgated by the DoE.

The RCC noted the presentation and approved for its posting in the WESM Market Information Website to solicit comments of the Participants and interested parties.

MNM Development and Maintenance Manual

Mr. Art Pintado presented the proposed changes to the MNM Development and Maintenance Manual. He stated that a complete restructuring of the Manual was made to address the following objectives:

- i. The existing Manual needs to be up-to-date with the existing protocols among the MO, SO, DOE, ERC, and TPs.
- ii. Address the findings and recommendations of the market operations audit
- iii. Implement the restructured format of WESM Manuals

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- iv. Provide clarity on the MNM development process.

Below are the major changes made on the Manual as presented by Mr. Pintado.

Major Changes to the Market Manual

Change	Highlights
<u>Responsibilities of Network Service Providers</u>	Included the responsibility of the Network Service Providers (or DUs) to submit to the System Operator network data that is under their control, that is included in the MNM. This is in anticipation of the possibility of modeling the Meralco Network and other DU system into the MNM.
<u>Deletion of pre-Commercial Operations procedures</u>	Removed the description of development of the network model prior to the commercial operations descriptions.
<u>Timeline of Activities</u>	This is the summary of all the internal and external processes involved in the maintenance of the MNM. The timeline is in a tabular format which is a summary of the current practices and also lists all the responsible parties concerned.



Major Changes to the Market Manual

Change	Highlights
<u>Notification of DOE/ERC for MNM uploading</u>	In the said timetable, the DOE/ERC shall be included in the advisories of the planned date of uploading the updated MNM in the production system of the MMS.
<u>Notification of final Energization Schedule</u>	Also in the timetable, the System Operator shall notify the Market Operator, the final schedule of equipment energization, at least two(2) calendar days prior to the said energization date.
<u>DUs to Provide network Data to System Operator</u>	Network Service Providers (DUs) are required to provide the System Operator with the relevant information of the changes to their network. The MO shall determine if the said distribution network should be included in the MNM.

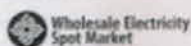


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Major Changes to the Market Manual

Change	Highlights
MNM Hardcopies	Instead of maintaining hard copies of MNM documents for each MNM revision, it is proposed that soft copies of the documents shall be maintained (Section 6.1.2).
PSSE files from the System Operator	Include a provision that will require the System Operator to regularly provide the Market Operator with an updated Single Line Diagram, and PSSE files. This is a recommendation of the HTWG. (Section 6.5.1)
Modeling of Station service use	Requiring the Generator Trading Participant to register its associated load resource to monitor its injection and withdrawal from the grid (Section 7.3.2)
Modeling of Embedded generators	Provided clarification to the modeling of embedded generator. The generation of the embedded facility shall also be accounted to the nearest load resource through the look-up table. (Section 7.4.7)



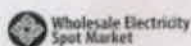
Major Changes to the Market Manual

Change	Highlights
Market Impact Study	Market Operator shall conduct a Market Impact Study (MIS) to identify if certain parts of the power system that is not modeled can have a material effect in the dispatch of scheduled generation in the WESM.



Major Changes to the Market Manual

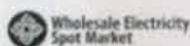
Change	Highlights
Removed Outdated Attachments	Removed the following attachments that are no longer applicable to the current operations. <ul style="list-style-type: none">- Appendix 2 Procedural Steps for Market Development (Pre Commercial Operation)- Appendix 3 Market Network Model Development prior to Market Trials- Appendix 4 Market Network Model Development prior to Market Operations- Appendix 5 Data for submission prior to market trial
List of Parameters required from the System Operator	New exhaustive list of power system parameters required for the development of the MNM (Appendix A). Parameters that are only relevant to the market operations were retained, and labelled as "Mandatory". All other parameters were either removed or noted as "As Available" from the list.



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Major Changes to the Market Manual

Change	Highlights
Network Transformer Modeling	Requirement to provide of resistance (R) parameter for network transformers (Appendix A)
Simplifications on the MNM	<p>Provided additional descriptions when the Market Operator in consultation with the System Operator can make the following simplifications and approximations to the representation of generator and customer trading nodes:</p> <ol style="list-style-type: none"> 1. Aggregated representation of generating units 2. Disaggregation of customer trading nodes 3. Simplification of sub transmission systems



Noting the proposal being submitted by PEMC is the restructured Manual instead of the matrix of proposed amendments, the RCC requested to be provided with the tracked version of the Manual, which was duly noted.

Following the presentation, the RCC approved for posting the revised Manual as proposed by PEMC.

Load Forecasting Methodology Manual

Mr. Edward Olmedo presented the proposed changes to the subject Manual. He stated that the Market Manual scored "Red" (Non-compliant) because of several issues on context, process, and governance. He said that the Market Manual was improved to reflect the existing practice of the Market Operator as well as the procedures it performs to comply with its obligations under the WESM Rules on load forecasting.

Below are the major changes made on the Manual.

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Major Changes to the Market Manual

Description of Change	Highlights
New Structure for Market Manuals	Implementation of new guidelines for writing Market Manuals, which includes prescribed formats and guidelines for content
Dedicated Sections for Demand Forecasts	Separate sections for Market Projections (WAP and DAP) and Hour-Ahead Forecasts
	Procedures on SDLF and LDP Methodology
	Overriding Functionalities for SDLF and LDP
	Distinction between Input and Final Demand Forecasts
Responsibilities in Load Forecasting	Highlight Specific Responsibilities of Market Operator, System Operator, and Trading Participants
	MO to maintain forecast methodology of Market Manual
	SO to provide most accurate real-time information
	TPs to ensure that if they do submit forecast, it is highly reliable

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Major Changes to the Market Manual

Description of Change	Highlights
Separate Section for Net Load Forecasts	Process of determining Unrestrained Net Load Forecasts for each Customer Node from Demand Forecasts for WAP, DAP, and RTD
	Use of Load Pattern as off-take for Unrestrained Net Load Forecasts for WAP and DAP
	Use of latest system snapshot as off-take for Unrestrained Net Load Forecasts for RTD
	Provision of functionality for overriding Unrestrained Net Load Forecasts through Customer Forecast Submissions
	Preparation of a Restrained Net Load Forecast to account for Load Shedding
	Definition of the "Initial Loss Percentage" for determining Unrestrained Net Load Forecasts from the Input Demand Forecasts
	New Compliance to publish "Initial Loss Percentage" in Market Information Website

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Major Changes to the Market Manual

Description of Change	Highlights
Customer Forecasts	Optional functionality for Customers to provide own Unrestrained Net Load Forecast
	A Customer with a dedicated MTN may submit a demand forecast
	Customer Forecast submission shall require approval from Market Operator
	Setting of Customer Forecast Tolerance Range based on approved percentage for determining regulation reserve
	Requirement to submit Load Information for TPs identified by Market Operator, particularly those who have material effect on the outcome of the demand
Load Forecasting Considerations	Weather Data Consideration (includes list of prospective weather data providers)

5

Major Changes to the Market Manual

Description of Change	Highlights
Other Load Forecasting Considerations	Load Demand to depend on the most accurate and reliable real-time information from System Operator
	The Default Customer Load Forecast of a Customer Node shall be established by the Market Operator in lieu of the TP's own forecast
	Consider load growth from Department of Energy (DOE)
Load Forecast Audit and Performance Measures	Refer to performance standards published by Market Operator
	Need for Evaluation of Net Load Forecast Performance
Appendix	Sample of LDP Methodology



9

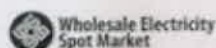
Following the presentation, the RCC approved for the posting of the Proposed Manual in the WESM Website, for comments of participants and interested parties. The RCC likewise requested to be provided with the tracked version of the Manual, which was duly noted.

Load Shedding

Mr. Olmedo presented the proposed changes to the Manual on Management Procedure for Load Shedding, stating that the proposal is being made by PEMC to address some issues on context, process, and governance. Following are the major changes made on the Manual.

Major Changes to the Market Manual

Description of Change	Highlights
New Structure for Market Manuals	Implementation of new guidelines for writing Market Manuals, which includes prescribed formats and guidelines for content
Context	<input type="checkbox"/> References to the WESM Rules <input type="checkbox"/> References to the Grid Code
Process	<input type="checkbox"/> Revised Responsibilities Section <input type="checkbox"/> Revised MLD Procedure <ul style="list-style-type: none"> Revised Pre-Condition Requirements <input type="checkbox"/> Revised ALD Procedure <ul style="list-style-type: none"> No Pre-Condition Requirements
Governance	As prescribed through the new format for Market Manuals



4






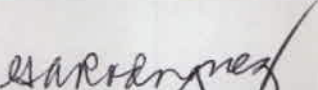

Following the presentation, the RCC approved for the posting of the proposal in the WESM Market Information Website, to solicit comments of participants and other interested parties.

5. Next Meeting

The RCC members were reminded of the schedule of its next meeting on 04 December 2013 at 9:00AM.

6. Adjournment

There being no other matter to be discussed, the meeting was adjourned at around 3:45 PM.

Prepared By:	Reviewed By:	Noted By:
 Romellen C. Salazar Analyst – Market Governance Administration Unit Market Assessment Group	 Geraldine A. Rodriguez Assistant Manager – Market Governance Administration Unit Market Assessment Group	 Elaine D. Gonzales Manager – Market Data and Analysis Division Market Assessment Group

<p>Approved by: RULES CHANGE COMMITTEE</p> <p> Rowena Cristina L. Guevara Chairperson Independent University of the Philippines (UP)</p>	
Members:	
<p>Concepcion I. Tanglao Independent</p>	<p> Francisco L.R. Castro, Jr. Independent Tensaiken Consulting</p>
<p> Maila Lourdes G. de Castro Independent</p>	<p> Lorreto H. Rivera Supply Sector TeaM (Philippines) Energy Corporation</p>

Moner



 Jose P. Santos Distribution Sector (EC) Ilocos Norte Electric Cooperative, Inc. (INEC)	 Ciprinilo C. Meneses Distribution Sector (PDU) Manila Electric Company (MERALCO)
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