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Final Report
Philippine Electricity Market Corporation

Final Report – Metering Arrangements Review for Philippine Electricity Market Corporation

19 March 2013

Isla Lipana & Co.

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Mr. Felixberto U. Bustos
Chairman, PEMC Audit Committee
Philippine Electricity Market Corporation
18/F Robinsons-Equitable Tower
ADB Avenue, Ortigas Center
1600 Pasig City, Philippines

Dear Mr. Bustos,

Final Report on the Metering Arrangements Review for Philippine Electricity Market Corporation (PEMC)

In accordance with our terms of engagement dated July 17, 2012, Isla Lipana & Co., a member firm of PricewaterhouseCoopers, in partnership with Alliance of Power and Energy Xponents (APEX), Inc. and Intelligent Energy Systems (IES) reviewed the adequacy and compliance with the requirements of the metering installations under **clauses 1.5 ("The Philippines Electricity Market Auditor") and 4.5.5.4 of the WESM Rules**, related manual and other applicable regulatory standards. Under these rules, the PEM Auditor, in consultation with the Market Operator and Metering Services Providers, shall review the security arrangements and requirement of metering installations annually.

Our work did not constitute an audit conducted in accordance with generally accepted auditing standards, an examination of internal controls or other attestations or review services in accordance with standards set by the Board of Accountancy in the Philippines. Accordingly, we do not express an opinion or any other form of assurance on the financial reports of PEMC. PEMC and National Grid Corporation of the Philippines (NGCP) as the Metering Service Provider (MSP), remains responsible for establishing and maintaining an effective internal control system as well as evaluating the effectiveness of said systems for the project. Likewise, PEMC and NGCP are responsible for providing all necessary documents needed by us to support the review. Our work solely depended on the information provided by PEMC, NGCP and other authorized third party.

Because of the limited scope and inherent limitation of this engagement, there is no guarantee that all matters of significance to PEMC and NGCP will be disclosed in our work. It is the responsibility of PEMC to determine whether the areas we covered and the extent of verification or other checking included in the Scope are adequate for their purposes and we make no representations in this regard.

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It is understood that this report is solely for the information of the addressee and identified PEMC representatives. This report or portion thereof should not be referred or distributed to any person or entity other than the addressees. Similarly, any other information or advice, written or oral, or whatever nature made available by us to PEMC are for their sole use and must not be disclosed or made available to any party without our prior written permission. In no event, regardless of whether consent has been provided shall we assume any responsibility to any third party to which the report is disclosed or otherwise made available.

We thank PEMC and NGCP for the cooperation and courtesies extended to us during the engagement.

Very truly yours,

For and on behalf of Isla Lipana & Co., the Philippine member firm of PwC (PricewaterhouseCoopers), as lead firm, in association with PwC India, Intelligent Energy System Pty Ltd (IES) and Alliance of Power & Energy Xponents Inc. (APEX)

[redacted]

Rossana S. Javier
Managing Partner
rose.javier@ph.pwc.com
T: (632) 845 2728 ext. 3016
F: (632) 824 2806

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Table of Acronyms

Acronyms	Expansion
AC	Alternating Current
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
AMR	Automated Meter Reading
ANEM	Australian National Electricity Market
APEX	Alliance of Power and Energy Xponents, Inc.
aseXML Standard	Standard for Energy Transaction of AEMO
ASTM	American Society for Testing and Materials
BCP	Business Continuity Plan
BSMD	Billing, Settlement and Metering Department
CATS	Consumer Administration and Transfer Solution
CCVT	Capacitance Coupled Voltage Transformers
CPC	Corporate Planning Communication
CT/PT	Current and Potential Transformers
DA	Department Administrator
dB	Decibels
DBA	Database Administrator
DBMS	Database Management System
DC	Direct Current
DLACR	Detailed Logical Access Control Report
DMC	Distribution Management Committee
DMS	Data Management System
DRP	Disaster Recovery Plan
DTS	Digital Telephone Systems
DU	Distribution Utilities
EDM	Energy Data Management
EMS	Energy Management System
ERC	Energy Regulatory Commission
ETRM	Commodity Trading and Risk Management
FTP	File Transfer Protocol
GMC	Grid Management Committee
GPRS	General Packet Radio Service
GPS	Global Positioning System
GSM	Global System for Mobile
ICT	Information and Communications Technology
IEC	International Electrotechnical Commission
IES	Intelligent Energy Systems
IMS	Information Management System
IOMD	Infrastructure, Operations and Maintenance Division

IP Rating	Index of Protection Rating
ISMS	Information Security Management System
ISO	International Organization for Standardization
IST	Information Systems and Technology
LNSP	Local Network Service Provider
LR	Local Retailer
MAG	Market Assessment Group
MDM	Metering Data Management
MDOM	Market Dispatch Optimization Model
MDP	Metering Data Providers
MDVS	Meter Data Validation System
MDW	Meter Data Warehouse
MIRF	Metering Installation Registration Form
MMS	Materials Management System
MMS	Market Management System
MNM	Market Network Model
MO	Market Operator
MP	Metering Providers
MQ	Meter Quantity
MSATS	Market Settlement and Transfer
MSD	Metering Services Department
MSP	Metering Services Provider
MSS	Metering Senior Specialist
MTD	Maintenance and Testing Division
MTN	Market Trading Node
MTR	Monthly Meter Trouble Report
MUT	Meter Under Test
mW	Milliwatt
NA	Network Administrator
NEM	National Electricity Market
NGCP	National Grid Corporation of the Philippines
NMI	National Metering Identifier
NSP	Network Service Provider
O/S	Operating System
ODBC	Open Database Connectivity
PAC	PEMC Audit Committee
PEMC	Philippine Electricity Market Corporation
PMO	Project Management Officer
PMTR	Polyphase Meter and Testing Report
PVC	Polyvinyl chloride
PwC	PricewaterhouseCoopers
PWS	Portable working Standard

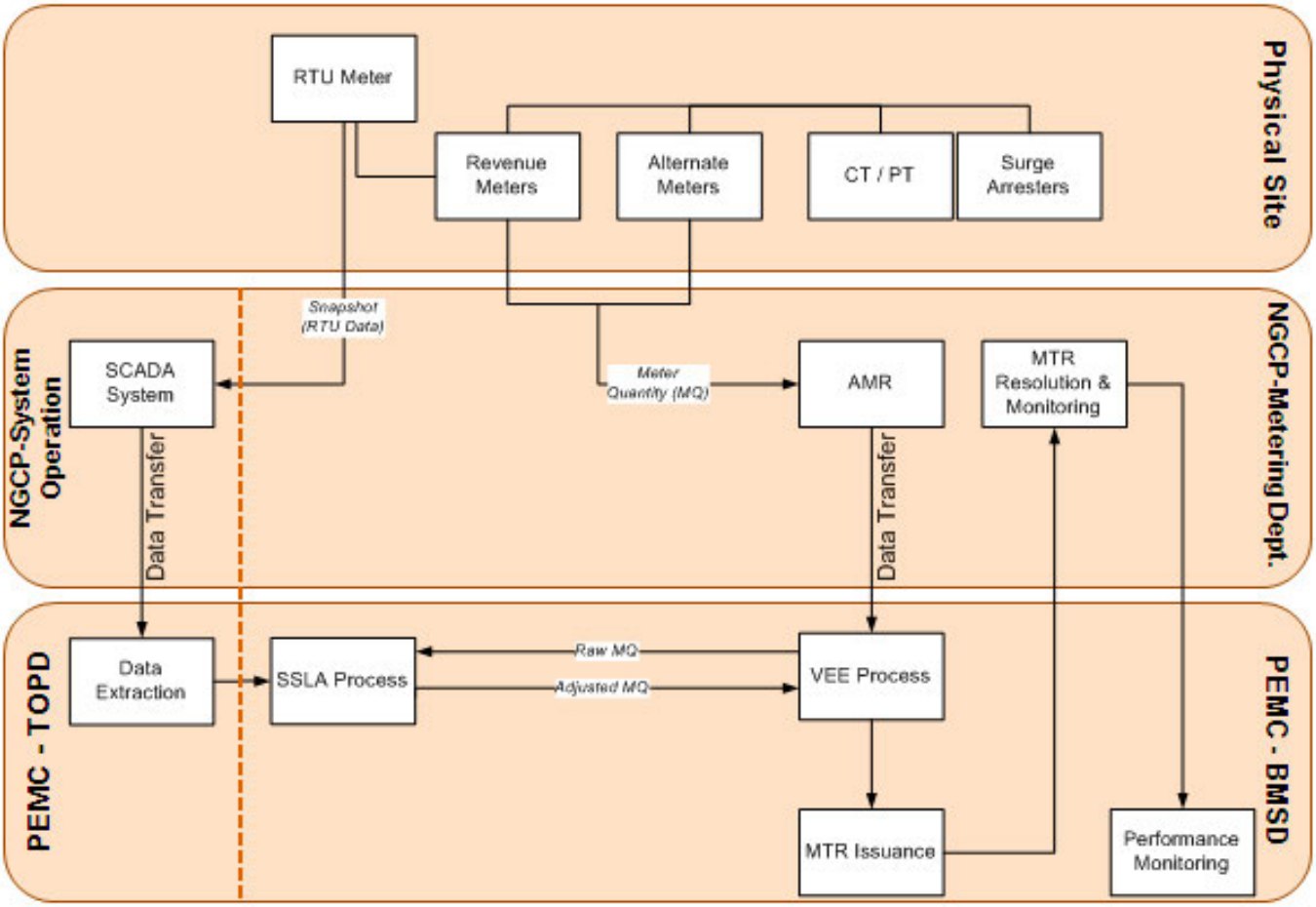
RSC	Rigid Steel Conduit
RTU	Remote Terminal Unit
SA	System Administrator
SCADA	Supervisory Control and Data Acquisition system
SEIN	Site Equipment Identification Number
SOD	Systems Operations Department
SQL	Structured Query Language
SSLA	Site-Specific Loss-Adjustment
SSLF	Site-Specific Loss Factors
TDP	Transmission Development Plan
TOPD	Trading Operations and Planning Department
TP	Trading Participant
TWG	Technical Working Group
UAT	User Acceptance Testing
UPS	Uninterruptible Power Supply
VBA	Visual Basic for Applications
VEE	Validation, Estimation and Editing
VPN	Virtual Private Network
WBSS	Wholesale Billing and Settlement System
WESM	Wholesale Electricity Spot Market

Executive Summary

The PEMC Audit Committee (PAC) have engaged Isla Lipana & Co., a member firm of PricewaterhouseCoopers, in partnership with Alliance of Power and Energy Xponents (APEX), Inc. and Intelligent Energy Systems (IES) to review the adequacy and compliance with the requirements of the metering installations under the WESM Rules in particular, **clauses 1.5** ("The Philippines Electricity Market Auditor") and **4.5.5.4** as well as related manuals and other applicable standards. Under the WESM rules, the PEM Auditor, in consultation with the Market Operator and Metering Services Providers, **shall review the security arrangements and requirement of metering installations annually.**

To meet these requirements, Isla Lipana & Co., APEX and IES developed applicable work programs that would cover the audit requirements of PEMC. Our test procedures were primarily based on the audit requirements of the corresponding Request for Proposal (RFP) and were anchored to the relevant provisions of the WESM Rules, related manual and other applicable standards. The test procedures performed were a combination of interviews, documentation reviews, systems and process walkthroughs and independent calculations based on information provided by PEMC and the metering service provider, which is the National Grid Corporation of the Philippines (NGCP). Major areas of review are as follows:

Figure 1: Areas of Review



a. Validation, Estimation and Editing (VEE) process
b. Site Specific Loss Adjustment (SSLA) process
c. IT General Controls testing on both PEMC and NGCP
d. Systems and Business Process review on both PEMC and NGCP
e. Physical inspection of the metering sites

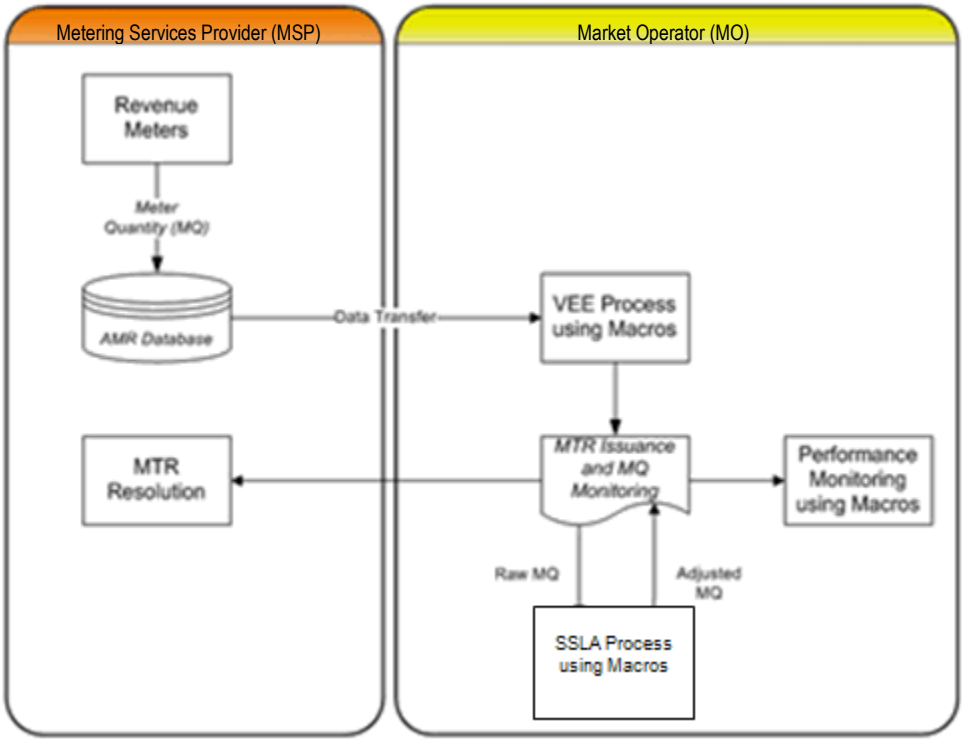
In addition, applicable industry best practices both locally and in other similar electricity markets (i.e. Australia, Singapore) were considered in the recommendations.

Key Recommendations

1. Revisit the current Market Structure to reflect best practices from other electricity markets

We recommend PEMC and MSP to evaluate and consider the market structure from other more mature electricity trading market such as those in Australia. Specifically, in developing a framework and structure that would enable them to efficiently share the responsibilities regarding the validation, estimation and substitution of metering data.

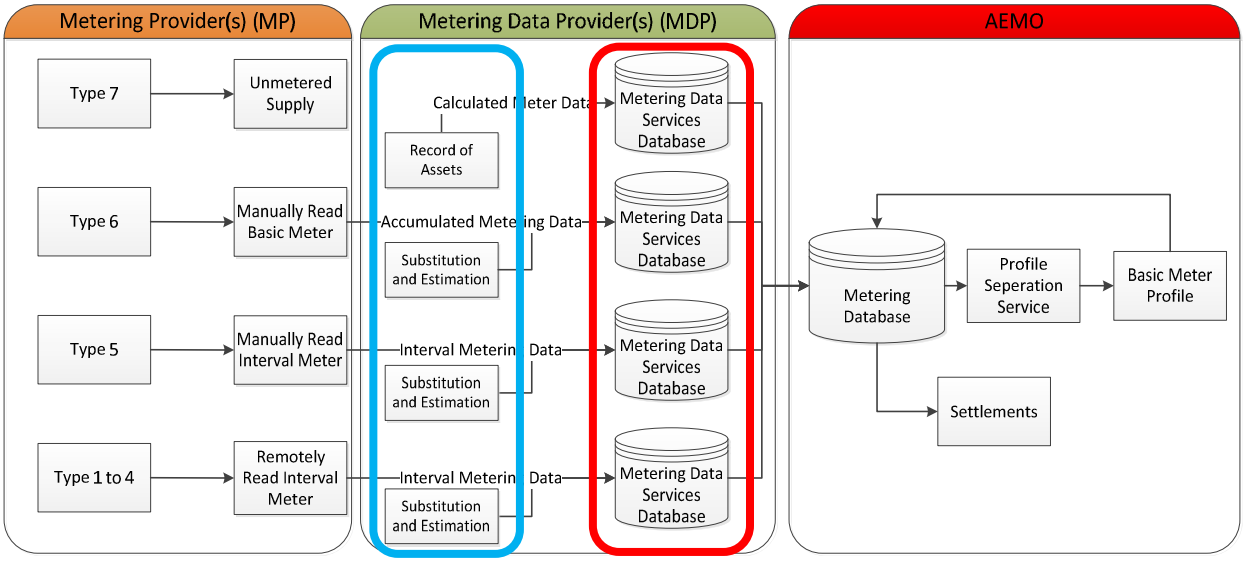
Figure 2: As-Is STRUCTURE



To better illustrate, the above figure *(Figure 2: As-Is STRUCTURE)* shows that PEMC and MSP have responsibilities in performing validations on the meter data but without clear boundary in terms of scope, roles and extent of validations to be performed by each. For example, MSP provides PEMC with pre-validated metering information on a daily basis. On the other hand, PEMC still applies additional validations on the meter data that was provided while summarising outcomes of the MSP's validations. As a matter of practice, both will inform each other of the need to perform corrections to the data during the billing month. At the end of each month, MSP will transmit to PEMC the raw and adjusted meter data for metering intervals that would further need some substitution procedures. PEMC would then analyse the substitutions made by

the MSP through the use of complex spread sheets. Obviously, the process described and implemented is tedious and error-prone.

Figure 3: BENCHMARK STRUCTURE



Note: Functions enclosed by blue box are currently performed by PEMC while those enclosed in red are currently performed by NGCP-MSD

As a best practice recommendation, we would like to highlight a potential setup such as that adopted by Australian National Electricity Market (ANEM) *(Figure 3: BENCHMARK STRUCTURE)* where checks and validation on the correctness of a MDP's substitution technique are carried out through annual auditing of the algorithms and procedures in place at the MDP. Also, the said setup is based on clear delineation of scope and responsibilities with regards to the processes involved in generating and validation of meter data.

Note that in the ANEM/Australian set up where it is largely retail, there are many MSPs instead of just one. Also, a separate entity (MDP) acts as bridge/inter-face between the various MSPs and MO. MDP is responsible for the validation of meter quantities, estimation and substitution.

When the local environment deems that the current structure migrate to the ANEM benchmark set up, the MDP activities currently shared by PEMC (MO) and NGCP (MSP) will entail the following:

- Creation of a separate a third entity acting as MDP
- Clearer segregation of roles and responsibilities between the MSP, MDP and MO
- Potential changes in existing WESM rules in support of the new set up.

2. Competitive Electricity Market

We highly recommend WESM to strongly enforce and support the provision related to engaging more than one MSP player in the market. As stated in WESM 2.3.6.3, there should be more than one MSP to promote a healthy and competitive environment that may help improve service delivery to the market operator and trading participants. As with other more mature markets such as those of Australia, the AEMO's setup allows for more than one MSP, which could be beneficial since a competitive environment is promoted and would normally result to higher quality and provision of services as opposed to a monopolistic environment currently in place at the WESM.

3. Revisit Market Operator Directorship

Table 1: Comparison with Other International Markets

	Philippines	Australia	Singapore
Electricity Market	Wholesale Electricity Spot Market (WESM)	Australian National Electricity Market (NEM)	National Electricity Market of Singapore (NEMS)
Market Operator	Philippine Electricity Market Corporation (PEMC)	Australian Energy Markets Corporation (AEMO)	Electricity Market Company Pte Ltd (EMC)
MO Ownership	Non-stock, nonprofit corporation made up of representatives from each sector of the electric power industry as well as independent members	Not for profit corporation jointly owned by the state governments	Completely owned by government entities
Board Composition	The PEMC Board is a **15-man body** as follows: • 1 Director representing the Market Operator • 1 Director representing the National Transmission Corporation (TransCo) • 1 Director from the Supply Sector • 4 Directors from the Generation Sector • 4 Directors from the Distribution Sector • 4 Directors independent of the Philippine electric power industry	The Board must consist of **between 5 and 10 Directors**, of which: • 1 will be the Chairman • 1 will be the Managing Director • At least 3 and no more than 6 are to have Industry Experience A majority including the Chairman are to be Independent i.e. have no material relationship with a market trading participant	• The Board is small, consisting of **three (3) people** with predominantly legal and corporate backgrounds with no direct industry connections. • Industry is represented on the various Panels that support the EMC. These include the Market Surveillance and Compliance Panel and the Rule Change Panel.

International practice as described above suggests that it is not necessarily inappropriate for an interested party such as a retailer to sit on the Board or the various Committees of a market operator such as PEMC. However, the fact that there have been unresolved issues, perhaps leading to non-compliance with the metering code, between PEMC and the business of one Director should have been known to the Board. It is not immediately clear whether the issue was ever raised with the Board by the Director concerned or by PEMC staff through PEMC Directors.

The conclusions of the audit on this matter are:

a. The unmetered off-takes by one retailer appear to be a significant departure from required metering practice
b. While it is not inappropriate for a retailer to sit on the PEMC Board, the Board should have been aware of the issue in case a potential conflict arose.
c. Procedures and sanctions should be in place to ensure that Directors inform the Board of any potential conflict and that staff inform the Board of any unresolved issues involving Directors.

4. Institute Process Automation initiatives

We recommend that the automation and streamlining initiative takes into consideration the level of precision that would be required in the various processes performed by PEMC and MSP. Note that automation of the process might not be possible in the short term but that a detailed policies and procedures manual could be started to lay the foundation for the implementation of such initiative. Specifically, we highlight the following areas:

4.1. System Integration

We note that it would be critical to reinstate the old MV90 in the Market Operator side so that retrieval and transmission of metering data would be continuous, faster and more secure. The current process of transmitting meter data by CD is lengthy and unsecure. Such might result to delays in the issuance of final settlements especially if meter data volumes are high.

4.2. VEE Automation

Ultimately, a formal list of substitution procedures to be applied in each case could allow for the automation of the process. If the procedures are laid out in a very precise and formal way, they could be translated into code that could automatically implement the procedures and generate a brief substitution report to inform the metering personnel of the substitutions that were made.

4.3. Improved SSLA Processing

Currently SSLA processing involves many activities implemented through spreadsheets and spreadsheet macros. The technical configurations required to be modelled are implemented and maintained in hundreds of spreadsheets. Each spreadsheet contains a mix of data and code which can be a challenge to maintain. For example, the audit discovered a small set of cases where an incorrect sign has been present. While macro automation is used to process a sequence of spreadsheet configuration files using current meter data, the intermediate processes are manual and potentially error prone. Another issue is that switching configurations that affect some calculations need to be inferred by reverse engineering rather than direct measurement and are not available until near the time of settlement. We propose that SSLA processing be carried out in an application that would remove the need to maintain and process multiple configuration spreadsheets, easing maintenance and speeding up processing. We outline the approach in more detail in the *Best Practices* section of the report.

5. Strict enforcement and compliance of Preventive Maintenance activities

The WESM Manual enumerates the different preventive maintenance services on metering installations required of the MSP, which includes, among others:

a. Meter reading
b. Periodic inspections

c. Metering security
d. Meter data communications service
e. Annual calibration and testing of meters
f. Testing of instrument transformers

As such, the MSP should ensure that these services are being performed in compliance with the WESM Rules and Manual. Part of this initiative is for PEMC, as the Market Operator, to enforce and reiterate these requirements among the Trading Participants/Customers. This could be further enforced through provisions of specific sanctions and penalties in the current provisions of the WESM Manual applicable to preventive maintenance activities. (Refer to *Best Practices* for more details*)*

6. Good housekeeping activities and procedures of different metering sites

Maintenance activities should not be limited to inspections and testing of metering equipments of the MSP. It should also extend to housekeeping activities including maintenance of site premises (i.e. compliance with perimeter fence requirements, ensuring no vegetation and adequate security in the premises, etc.), and good record keeping.

7. Formalization and diligent performance of pilferage audits

In addition to the existing roles and obligations of the MSP in the WESM Rules and Manual, the periodic conduct of surprise visits (e.g. pilferage audits) should be strongly considered given the susceptibility of electricity to pilferage and availability of ways to circumvent the proper recording of energy consumption (e.g. tampering of meter facilities). Corresponding policies and procedures should be formalized in the WESM Manual to ensure clear-cut guidelines on how the audit would be performed and reported. If adopted, this will certainly minimize the potential risk of pilferage and tampering among the different Trading Participants. Also, this will send a strong message regarding the market's intention of promoting transparency and integrity among the players in the WESM.

8. WESM Manual may be further developed to include specific guidelines on areas such as:

a. Monitoring of updates and changes made to any installations in the metering sites.
b. Establishment of a database that will reflect or record historical information from MIRF and subsequent changes made to all metering installation.
c. The use of a single standard document for the approval process of the request for metering installation changes.
d. Inventory monitoring procedures for the use of seals that may include the following:
    - Use of a document, similar to a stock card whenever a batch of seal is issued to each MTD staff.
    - Periodic updates to the custodian of the used seals supported by the PMTR or any other document prepared during the preventive maintenance.
    - Return of the seals removed from the metering sites for proper accounting / recording
    - Periodic reconciliation of the unused seals on –hand per MTD with the record of the custodian.
e. Revision of the grounding requirements which would make spot check activities of the grounding resistance measurable and reliable.
f. Regular grounding checks should also be required by WESM to ensure the stability of the grounding facility.
g. Inclusion of various checks of the physical condition of the instrument transformer structure in the preventive maintenance activities.
h. Maintenance of records regarding the results of preventive maintenance (PM) including the meter installations' physical condition in central database. This record should be able to track the remediation activities performed and whether there are findings noted in each PM activity

i. Generation / preparation of a report on a regular basis which monitors the number on meter installation which has outstanding PM finding and/or the number of days it is outstanding. This is to track how efficient metering staffs are in finding resolution.
j. Sanctions and penalties to be imposed for non-compliance to preventive maintenance provisions in WESM Manual
k. Clear definition of roles and responsibilities between concerned parties regarding preventive and corrective maintenance procedures
l. More specific provisions regarding acceptable time discrepancies between meter time and system time to better reflect realistic scenarios.

9. Strive to obtain higher IT Maturity Level

We highly recommend that both PEMC and MSP continue improvement initiatives on its information security policies and procedures. As a result of our assessment, PEMC and MSP garnered 3.01 and 2.00 points, respectively. Our assessment shows that much can be done to further improve and optimize the current IT security processes of PEMC and MSP.

10. Transfer to Central IT the maintenance and administration of MO Systems and Applications

We recommend Billing, Settlement and Metering Department (BSMD) to turn-over the administration, maintenance and monitoring of its systems and applications to the IT department to ensure that controls are consistently enforced. This would also ensure that such systems and applications would be subjected to regular maintenance and security improvement procedures.

Key Findings

We highlight below the following critical observations, exceptions and control gaps that must be addressed immediately.

a. Major Non-Compliances

Absence of meter seals on meter components (MI-PI12)

- 10 out of 216 **(4.62%)** main meters and 6 out of 216 **(2.77%)** alternate meters have no seal on the meter terminal
- 4 out of 216 **(1.85%)** main meters and 3 out of 216 **(1.38%)** alternate meters have no seal on the demand reset
- 4 out of 216 **(1.85%)** main meters have no seal on the test block
- 55 out of 216 **(25.46%)** current transformers and 65 out of 216 **(30.09%)** potential transformer have no seal on the secondary terminal boxes

Non-compliances on the perimeter security requirements (MI – PI17, MI – PI18, MI – PI19 & MI – PI20)

- 4 out of 216 **(1.08%)** metering installation have no perimeter fence while 2 out of 216 **(0.92%)** are broken down.
- 9 out of 216 **(4.19%)** metering installation uses Bermuda grass or concrete instead of gravel.
- 19 out of 216 **(8.8%)** metering installation are not well-lighted.
- 38 out of 216 **(17.59%)** has uncontrolled vegetation.

b. Incidental Non-Compliances

Adjusted Loads vs. Site Specific Loss Factors (PEMC-SSLA02)

In the monthly SSLA results provided, the review team have identified a number of meters which follows a different expression as compared to current practices of BSMD. The list of IDs for these meters is as follows:

a. MF3MBOHBLCI03
b. MF3MBOHBOH104
c. MF3MGARPMSC01
d. MF3MUBABOH201
e. MF3MUBABOH205
f. MF3MUBAMARC01

Non-functional Display (MI-PI03)

During the physical site inspection, it was discovered that **27 out of 216 (12.50%)** main meter installations and **5 out of 216 (2.31%)** of the alternate meters have non-functional displays (burnt-out, blurred, or flickering). Also, for main revenue meters, the brand that encounters the display functionality issues is EIG Nexus 1272.

Meter Time vs. System Time (MI-PI04)

It was noted during the physical site inspection that out of 215 metering installations, **79** or **36.57%** have time discrepancies of less than five (5) minutes in the main meter while **9** or **4.17%** metering points were noted to have time discrepancies of more than five (5) minutes.

For the alternate meters, **71** or **32.87%** metering points were noted to have time discrepancies of less than five (5) minutes and **26** or **12.04%** metering points were noted to have time discrepancies of more than five (5) minutes.

Among the exceptions with large time differences are the following:

a. MNORTRAN02 (Main Meter) - 7 hours and 54 minutes
b. QTUVECO13 (Alternate Meter) - More than one 1 year
c. MNORTRAN01 (Alternate Meter) – 20 days, 4 hours and 46 minutes
d. MBTNBTNG02 (Alternate Meter) - 5 hours and 51 minutes

Cabinet Housing (MI-PI05)

It was discovered that **20 out of 216** meter enclosures are inadequate (**17 out of 216 (7.87%)** meter installations are corroded, rusted or needs repainting, **1 out of 216 (0.46%)** has ill-fitting doors and **2 out of 216 (0.93%)** need immediate replacement.). Furthermore, the ingress of animals such as lizards and water, were also observed to exist in some meter enclosures.

Enclosure Security (MI-PI08)

It was observed during the physical site inspection that **27 out of 216 (12.50%)** sites did not use padlocks as a security measure for the meter enclosure. Moreover, some meter enclosures did not have provisions (hasp) for the installation of padlocks while others were designed using keyed (or cabinet) locks that are loose and easy to be picked.

c. Non-Compliances to Documented Internal Business Procedures

Work Instruction Manual (PEMC-ITGC01)

Work Instruction Manual provided by BSMD does not include information processing controls. In addition, it is not documented so as to be aligned with the ISO standard implemented for PEMC. At a minimum, the Procedure Manual should include the following:

a. Access Matrix
b. User Access Registration and Review procedure
c. Backup procedures (since almost all processes includes the use of macro-based programs and spreadsheets)
d. Periodic Review of the results of processes

This is with the understanding that POMAX, MV90, macro-based programs and spreadsheets used by BSMD is not maintained and/or monitored by the central IST.

User Access Management (PEMC-ITGC02)

a. Maintenance of the POMAX and MV90 is not under the IT Department. As a result the access rights are not requested through the said department and are maintained by the Metering Department.

b. Metering Department, however, does not follow any formal procedure on creating and updating access rights in the aforementioned systems.

c. Metering Department uses only one (1) user ID for accessing POMAX (Username: HANDEL) which is shared by all the Metering Senior Specialist.

d. There are three (3) access rights created in MV90 with the following status:
   - CRSCALUB: assigned to a MSS with administration and super user access rights. This ID has a system administration rights and can access all the functionality of the system.
   - JLVPAZ: assigned to a MSS with administration and super user access rights.
   - RBAFURONG: assigned to the Metering Assistant Manager with view and edit access rights to the system data and master files.

e. No defined access matrix is present for both MV90 and POMAX.

Use of User ID (PEMC-ITGC03)

The User ID used by IT for resolution of errors / trouble shooting encountered using POMAX (ex. Errors regarding system configuration or system data processing) is the same User ID (username: HANDEL) used by the rest of the MSS for data processing.

Formal User Access Review Process (PEMC-ITGC04)

There is no formal documentation of the review of the access rights for MV90 and POMAX.

d. Observations Requiring Immediate Corrective Action

Market Operator's highly manual business process (PEMC – VEE01)

The review team noted four (4) control gaps that were constantly present in various processes of BSMD. These control gaps occurred sixty-nine (69) times through-out the VEE and SSLA Processes. Nature of these control gaps were mainly unprotected data files, manual copy-paste activities and manual updating of masterfiles. Presence of these control gaps increases the risk of invalid and inaccurate outputs of the VEE and SSLA processes.

Manual elements in the issuance of the Monthly Metering Validation Report (PEMC – VEE08)

To effectively carry out the VEE process, error flags for the discrepancies in the "SSLA Raw vs. CD Validation Report" and "WESM-MET MF Validation Report" are manually removed for special cases where multiple MTNs share one metering installation.

Results of the analysis between reconciled Site Specific Loss Adjustment vs. SSLA Model (PEMC – SSLA01)

The review team have observed instances of days where changes in shifting configuration occurred while the reconciled results did not reflect a sequence of SSLA models consistent with the sequence of shifting configurations. Thus, there have been instances where the adjustment methodology referred to in clause 3.2.2.3 of the WESM Rules was not correctly implemented by the Market Operator.

Observations on the output of the SSLA Data (PEMC – SSLA03, PEMC-SSLA04 & PEMC – SSLA05)

- Presence of unusually large line losses in SSLA Data (SSLA03) of **Sun Power metering sites** (MF3MCLNMECO01 and MF3MCLNMECO0e) due to the treatment of an unmetered embedded load, and where BSMD has no knowledge of the switching configuration.
- Presence of large negative line losses in SSLA data of **BENECO metering site** (MF3MITOBENE08) due to a complex arrangement of incompletely metered embedded generation and loads, and where BSMD has no single line diagram.
- Presence of large line losses in SSLA data of **CEPZA metering site** (MF3MROSCEPZ03) due to the presence of a virtually embedded meter having multiple supplier, and where the BCQ (the quantity agreed by the TP and their customer) of the virtual meter is deducted from the adjusted MQ.

Observations on the Market Network Model (PEMC – MTNL01)

In some cases, the selection of monitoring points in the MNM does not allow for most accurate representation of physical losses on the network, in particular, between metering installations and MTN in particular. In other words, metering points can be allocated to distant MTN which, in turn, results in the calculation of losses and load adjustments that are not consistent with physical flows of energy on the network.

Please note that we were not able to assess how good a representation of the mapping between metering points and MTN BSMD's equations actually are. Making this assessment requires independent determination of the mapping in question and this can only be achieved by reviewing the physical metering installations and the Market Network Model. Single line diagrams of the metering installations were officially requested from the NGCP on a number of occasions but unfortunately these were not provided to us in the time available.

Insufficient user password management (PEMC – ITGC05)

- Passwords in both MV90 and POMAX were not configured to have an automatic reset setup for a time period.

- All the Macro-based programs except LUZ_VIZ_CONVERSION PROGRAM NTH.XLS - a program used for market fees and WESM MET generation, used by Metering Department are password protected. However, such password is shared by all the Metering Senior Specialists.

Insufficient MIRF record keeping and maintenance (MI – PI01)

There is no formal policy that governs the monitoring of updates made to any installations in the metering sites. As such the following discrepancies were noted between the results of the physical inspection and the details in MIRF:

- An average of **63%** discrepancy between the main meter details
- An average of **54%** discrepancy between the alternate meter details
- An average of **51%** discrepancy between the potential transformer – phase A
- An average of **25%** discrepancy between the potential transformer – phase B
- An average of **30%** discrepancy between the potential transformer – phase C
- An average of **52%** discrepancy between the current transformer – phase A
- An average of **53%** discrepancy between the current transformer – phase B
- An average of **53%** discrepancy between the current transformer – phase C

Insufficient meter seals inventory and log (MI – PI11)

- The amount/volume of meter seal provisions distributed / issued to each staff and the range of serial numbers it contains were not traceable to any transfer document for accountability.
- The serial numbers of seals pulled out from / returned to the stock room, and removed from / installed to the meter sites were not recorded and/or monitored for inventory purposes.
- The serial numbers of the seals installed to the secondary terminals and instrument transformers were not recorded / monitored in any documents

High Grounding Resistance in Instrument Transformers (MI – PI16)

60 out of 216 **(27.78%)** sites visited have resistance measurement of more than 5 Ohms. Please note that due to the complexity of determining the Earth Fault factor per metering site location as required by Philippine Grid Code, Section 4.2.8 – Grounding Requirements, a spot check on the grounding installation was conducted instead. A maximum limit of 5 Ohms was used in determining the acceptable resistance level which is found suitable for industrial plant substations, buildings and large commercial installations.

Inconsistencies on the structure of Instrument Transformers (MI – PI15)

We noted some inconsistencies against the industry standard in the metering installation structure components (e.g. terminal, tank casing, primary wires and cables, secondary wires and cables, material on secondary conduit, mounting structure and bushing). Also, some of these components are:

- Corroded
- Rusted
- Heavily oxidized with signs of fraying and discoloration
- Mounted on an elevated platform with rotten wood
- With traces of oil leak at the bottom/tank flance
- With exposed secondary leads.
- Have contaminated bushing (salt accumulation)
- Conduits found with breaks
- Wires are somewhat accessible

- Apparent exposure (outside conduit) of the secondary wires from box (sec term) to splicing box.

A summary of the observations noted by the team is as follows:

Table 2: Count of non-compliances to the WESM Rules, related provisions and documented internal business procedures per Area of Review

Area of Review	Critical non-compliance	Major non-compliance	Incidental non-compliance	Non-compliance to internal procedures	Total non-compliances
Validation, Estimation and Editing Process Review and Data Accuracy Testing	0	0	0	0	0
Site-Specific Loss Adjustment Process Review and Data Accuracy Testing	0	0	1	0	1
Appropriateness of Revenue Metering and Market Trading Node Location	0	0	0	0	0
MO - IT General Controls	0	0	0	4	4
MSP - Business Process Review	0	0	0	0	0
MSP - IT General Controls	0	0	0	0	0
Physical Site Inspection	0	2	4	0	6
Meter Integrity Testing	0	0	0	0	0
Total non-compliances					11

Best Practices

This section provides a guide on better practices in metering and better practice concepts in the following areas:

a. Organisational structure
b. Market Operator directorship
c. Market rules and manuals
d. Implementation of market rules
e. SSLA Calculations
f. Metering installations

Based on our understanding of the metering operations in place, we present specific practices that could prove better practice for the WESM. We will focus heavily on the Australian National Electricity Market (ANEM). Current metering arrangements in the ANEM have been in place for well over 10 years over which time they have been through numerous refinements. As the ANEM represents a market with regions of fully contestable retail sectors, it represents a good model from where the WESM may seek to transform to in the near-term future.

1. Organizational Structure

1.1. Metering Procedure

In the National Electricity Market of Australia, there are three different roles in the process of metering and settlement:

a. ***Metering Providers (MP)*** are responsible for the installation and maintenance of metering installations

b. ***Metering Data Providers (MDP)*** are responsible for the following functions:

- Collection of metering data
- Processing of metering data such as data validation, estimation and substitution
- Transferring the validated metering data to the Australian Energy Market Operator (AEMO).

Currently there are 20 MDPs in ANEM which carry out these services.

c. ***AEMO*** receives metering data from accredited MDPs and is responsible for the billing and settlement.

MDPs download electricity metering data from metering installations at the end of each billing period which is seven days – from Sunday 12:30 am until the next Sunday at 12:00 am. The validated metering data, including estimation and substitution of any missing or erroneous intervals should be forwarded to AEMO two (2) days after each billing period.

AEMO then calculates the wholesale electricity market transactions for each market participant using the regional reference price, transmission loss factors and the metering data for the market participant's connection points.

Figure 4: Metering Data Processes for meters in the NEM

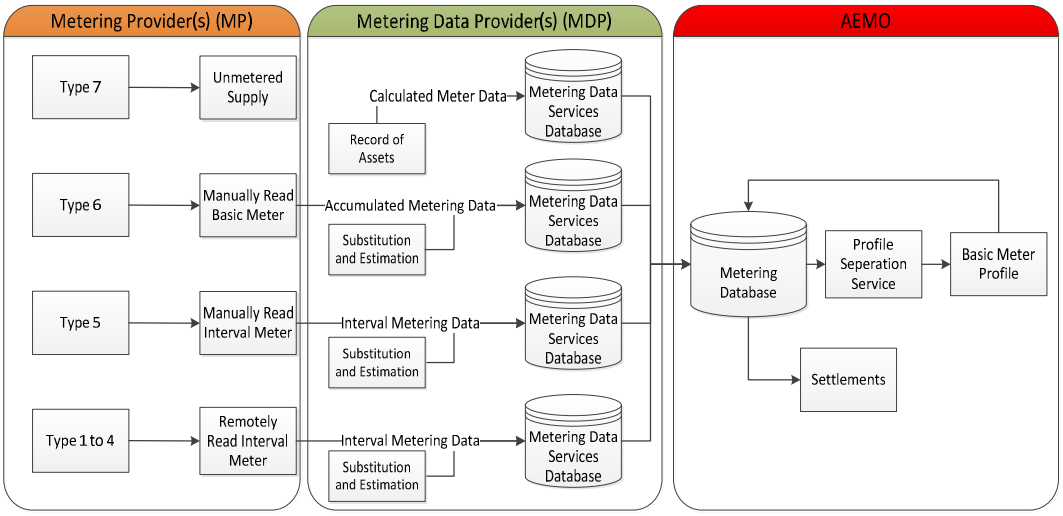


Figure 4: Metering Data Processes for meters in the NEM gives an overview of the metering processes applied by metering providers (MPs), Metering Data Providers (MDP) and the Market Operator (AEMO).

1.2. Types of Metering Installation

AEMO differentiates between seven types of metering installations. For each metering installation, a specific set of requirements in terms of accuracy and procedures applies. Table 5 provides the classification of each type of metering installation in accordance with Section 7.2 of the National Electricity Market Rules.

Table 3: Types of Metering Installations in the ANEM

Type	Classification	Meter Reading	Volume
1	Interval meter	Remotely read	More than 1000 GWh
2	Interval meter	Remotely read	100 to 1000 GWh
3	Interval meter	Remotely read	0.75 GWh to less than 100 GWh
4	Interval meter	Remotely read	less than 750 MWh
5	Interval meter	Manually read	Depending on Region: New South Wales, Victoria, South Australia: less than 160 MWh Queensland and Tasmania: less than 0 MWh
6	Basic Meter	Manually Read	Victoria and South Australia: less than 160 MWh New South Wales: less than 100 MWh Tasmania: less than 150 MWh Queensland: less than 100 MWh or less than 750 MWh for customers that are not Queensland market customers
7	Unmetered supply	Unmetered supply	Usually small volume installations where metering would not be practicable (street lighting, traffic lights, surveillance systems…)

Metering installations of types 1-4 are remotely interrogated interval meter installations. Type 5 metering installations are manually read interval meters. Type 6 pertains to accumulation metering installations that are read manually. Type 7 installations constitute metering installations that are too small to merit automatic communication links and MDPs estimate the interval metering data for these installations.

1.3. Metering Data Process for MDPs

MDPs are accredited by AEMO, in accordance with the Metering Service Provider Accreditation and Registration Procedure, and must demonstrate their capabilities in performing metering data services as detailed in AEMO's Service level procedures for Metering Data providers within the ANEM. Depending on the level of certification MDPs may only be permitted to process specific classes of meters.

Figure 5: Meter Data Process for Metering Data Providers lays out the process involved in the provision of metering data to AEMO that a MDP has to follow.

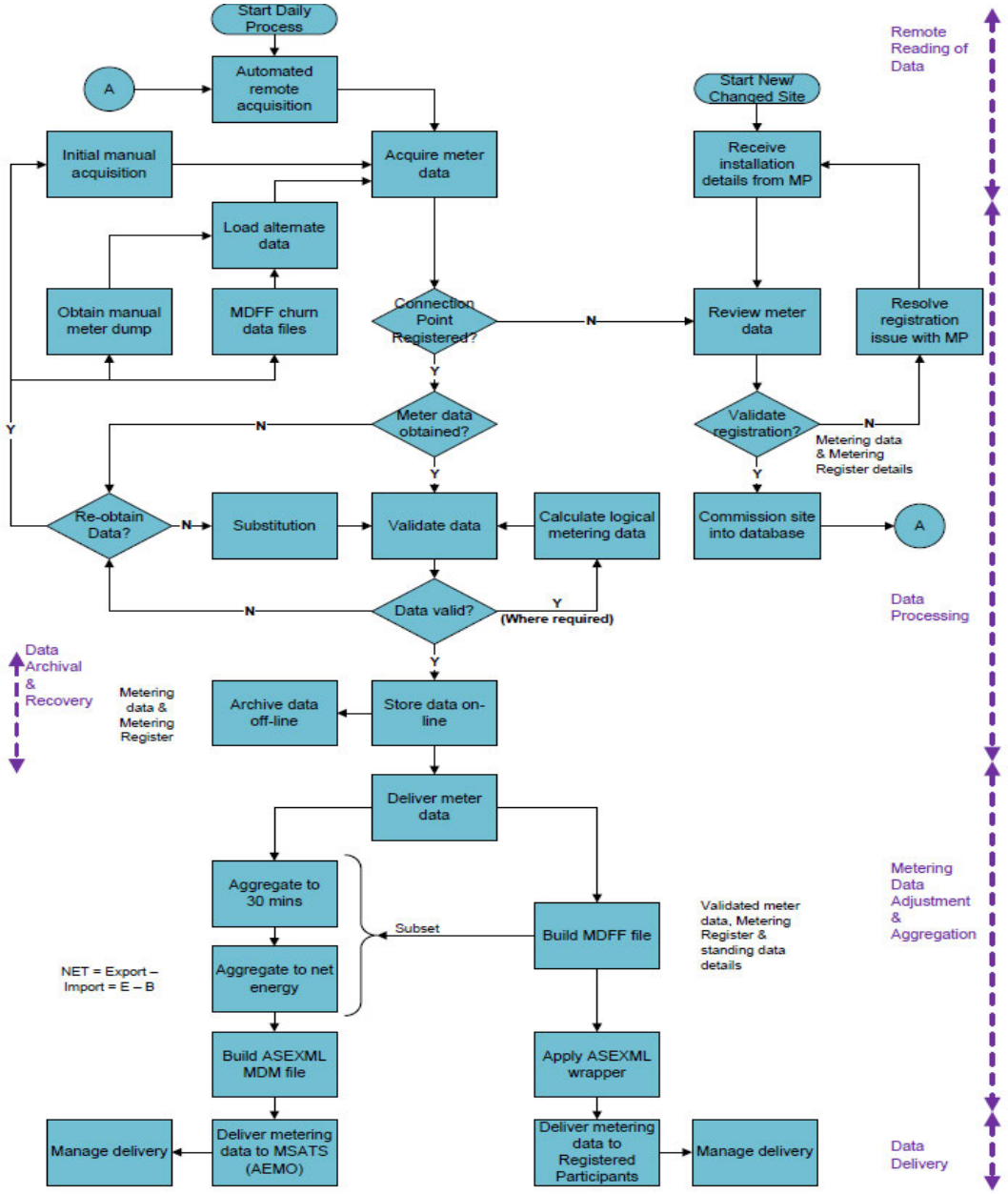
The metrology procedures part B lay out the requirements for the validation of each type of metering installation. A key requirement of the metrology procedures is that all validation, substitution, editing and estimation techniques must be applied in an auditable manner.

We note that AEMO does not carry out any estimation or substitutions of metering data. While AEMO performs a set of validations upon data it receives from the MDPs it will refer any potential erroneous readings back to the MDPs which will perform estimation and substitution.

AEMO's software solution – Market Settlement Transfer (MSATS) – will automatically check data before it is uploaded into AEMO's database by performing a range of automatic checks. The software solution will dynamically upload any data that has a higher version number or constitutes data from a later date than data already in the database. AEMO performs a set of checks on this data by running a set of standard SQL database queries to check for high or low readings and to check for instances where no data has been delivered.

In summary, AEMO oversees the processes employed by the MDP. While it performs some final validations of data delivered by the MDPs it does not perform any estimations, editing or substitution of data, this responsibility lies with the MDPs.

Figure 5: Meter Data Process for Metering Data Providers



Best Practice Recommendation

In WESM, NGCP and PEMC both perform validations on the meter data; however, the boundary scope of the validations performed by each entity is not entirely clear. For example, MSP provides PEMC with pre-validated metering information on a daily basis. PEMC then applies additional validations on the meter data and /or summarises the outcomes of MSP's validations.

Both organisations proceed to inform each other about the need for corrections to the data during the billing month. At the end of the month NGCP then sends PEMC a CD that contains raw and adjusted meter data for metering intervals where a substitution is necessary. PEMC analyses the substitutions made by NGCP by comparing spread sheets containing raw and adjusted meter

values.

In ANEM, checks on the correctness of a MDPs substitution technique are carried out by auditing the algorithms and procedures in place at the MDP on a yearly basis. Instead of being able to audit the methodology that is applied for a specific situation were substitution might become necessary, PEMC has to analyse specific substitutions on a case by case basis. This procedure is only possible where the amount of necessary substitution is small.

We would recommend that PEMC works closely with NGCP in developing a framework that enables the two entities to share the responsibilities for the validation estimation and substitution of metering data.

2. International Practice for Market Operator Directorship

Table 4: Comparison with Other International Markets

	Philippines	Australia	Singapore
Electricity Market	Wholesale Electricity Spot Market (WESM)	Australian National Electricity Market (NEM)	National Electricity Market of Singapore (NEMS)
Market Operator	Philippine Electricity Market Corporation (PEMC)	Australian Energy Markets Corporation (AEMO)	Electricity Market Company Pte Ltd (EMC)
MO Ownership	Non-stock, nonprofit corporation made up of representatives from each sector of the electric power industry as well as independent members	Not for profit corporation jointly owned by the state governments	Completely owned by government entities
Board Composition	The PEMC Board is a **15-man body** as follows: • 1 Director representing the Market Operator • 1 Director representing the National Transmission Corporation (TransCo) • 1 Director from the Supply Sector • 4 Directors from the Generation Sector • 4 Directors from the Distribution Sector	The Board must consist of **between 5 and 10 Directors**, of which: • 1 will be the Chairman • 1 will be the Managing Director • At least 3 and no more than 6 are to have Industry Experience A majority including the Chairman are to be Independent i.e. have no material relationship with a market trading participant	• The Board is small, consisting of **three (3) people** with predominantly legal and corporate backgrounds with no direct industry connections. • Industry is represented on the various Panels that support the EMC. These include the Market Surveillance and Compliance Panel

	• 4 Directors independent of the Philippine electric power industry	and the Rule Change Panel.

2.1. Background

The metering audit discovered a number of anomalies in the SSLA procedures whereby apparently large losses were incurred between the market node and the revenue meter, giving anomalous SSLA results. Process owners (both PEMC and NGCP) indicated that this outcome was due to unmetered loads being taken from this line. One of the off-takers was identified as a provincial retailer involved was also identified as a Director on the PEMC Board, indicating that there may be some sort of conflict of interest involved. While PEMC and NGCP staff members have been trying to resolve the matter with the retailer, it remains unresolved and must have been so since market start.

The audit has examined some cases of international practice to help come to a view as to whether there is some structural adjustment required to governance arrangements to avoid any real or potential conflicts of interest between PEMC and its Directors.

2.2. Australia

In Australia, the market operator is the Australian Energy Markets Corporation (AEMO)

a. AEMO is established as a not for profit corporation charged with efficient operation of the Australian National Electricity Market (NEM). It operates under a published constitution, available at http://www.aemo.com.au/About-AEMO/Board-and-Governance
b. AEMO is jointly owned by the state governments in which the NEM operates as well as the federal government. These governments jointly appoint the Board of Directors according to a set of guidelines laid out in the AEMO Constitution.
c. The constitution specifies (Clause 7.1) that the Board must consist of between 5 and 10 Directors, of which
    - One will be the Chairman
    - One will be the Managing Director
    - At least 3 and no more than 6 are to have Industry Experience (Schedule 2)
    - A majority including the Chairman are to be Independent i.e. have no material relationship with a market trading participant (Clause 7.2 and Schedule 2)
d. In event of a potential conflict of interest on a matter under consideration by the Board, a Director must declare that interest and, if other Directors determine) absent himself/herself from the discussion and voting on the matter (Clause 7.11 and also a part of general Corporations Law).

It is noteworthy that Clause 7.11 allows a great deal of latitude for a Director to have commercial interests either with AEMO itself or organisations affected by AEMO activities (e.g. trading participants). Indeed, such connections are inevitable if Industry Experience is to be one selection criterion.

The thinking behind this approach to governance extends back the initial electricity reform in Australia that took place in the state of Victoria from 1993. The potentially conflicting considerations when appointing Directors to the market operator Board were:

a. The perceive need to hear the voice of the parties directly affected by Board decisions, and to take account of their knowledge, and experience; and

b. The need to avoid turning the market operator into an industry club operating against the interests of the public, and to avoid any scope for special favours being given to specific organisations

The solution has been to allow and indeed require industry participation, but to ensure that these interests do not dominate or determine Board outcomes by requiring a majority of Directors to be independent. The apparently lenient provisions of Clause 7.11 are designed to ensure that no qualified candidate is excluded. On the other hand, the general requirement under Corporate Law to declare interests and abstain from debate and voting if required by fellow Directors is enforced. Failure to declare a potential conflict interest is a serious misdemeanour.

The current AEMO Board consists of current and recent executives or directors of market and network operators, industry regulators and executives associated with the energy industry, not always as trading participants. There is a considerable breadth of expertise from the technical to accounting and risk management. It is noteworthy that the number of Directors that might be considered as direct industry representatives currently numbers only two out of a total of nine

2.3. Singapore

Following is a very brief description of the market governance practice in Singapore.
The National Electricity Market of Singapore (NEMS) is operated by the Electricity Market Company Pte Ltd (EMC). This used to be 51% owned by the Energy Market Authority (EMA) and a private company, but is now completely owned by government entities. The market is operated on a regulated return basis.

The Board is small, consisting of three people with predominantly legal and corporate backgrounds with no direct industry connections. Industry is represented on the various Panels that support the EMC. These include the Market Surveillance and Compliance Panel and the Rule Change Panel. In Australia, these functions are performed by separate regulatory entities although AEMO does retain some of these functions.

These arrangements differ in detail from those applying in Australia, as would be expected. However, in both cases the need to have an industry presence when key matters affecting the market are under consideration is recognised.

2.4. Implications for PEMC

International practice as described above suggests that it is not necessarily inappropriate for an interested party such as a retailer to sit on the Board or the various Committees of a market operator such as PEMC. However, the fact that there have been unresolved issues, perhaps leading to non-compliance with the metering code, between PEMC and the business of one Director should have been known to the Board. It is not immediately clear whether the issue was ever raised with the Board by the Director concerned or by PEMC staff through PEMC Directors.

The conclusions of the audit on this matter are:

d. The unmetered off-takes by one retailer appear to be a significant departure from required metering practice
e. While it is not inappropriate for a retailer to sit on the PEMC Board, the Board should have been aware of the issue in case a potential conflict arose.
f. Procedures and sanctions should be in place to ensure that Directors inform the Board of any potential conflict and that staff inform the Board of any unresolved issues involving Directors.

3. Practical Implementation of Market Rules

3.1. Validation Procedures

MDPs must validate metering data against meter data alarms in regards to power failure, voltage transformer or phase failure, pulse overflow, CRC errors and time tolerance errors. While these errors are raised automatically by interval metering installations, MDPs must process the alarms and retain exception reports that detail the type of alarm raised and any subsequent actions taken.

For manually read metering installations (type 5&6), MDPs are required to ensure that the metering serial number for an installation is correct by checking it against the recorded metering serial number. MDPs must also ensure that the physical security of metering installations is intact and that the metering device as well as any load control devices are synchronised to Australian Eastern Standard Time (AEST).

As type 6 meter installations represent accumulation meters, MDPs must ensure that current meter readings are greater than previous meter readings. Other checks for type 6 meter installations include:

a. Check that current meter value lies between an expected minimum and maximum
b. Check of dial capacity against recorded dial capacity

During registration or after reconfiguration of metering installations, MDPs have to perform a set of registration validation procedures. All validations procedures within the registration process have to be carried out before any actual metering data is submitted to AEMO. The National Metering Identifier (NMI) plays an important role in the registration of metering installations.

NMI is a ten character numerical identifier code used by AEMO to link metering data to the relevant connection points. For manually entered data, the NMI includes an eleventh check-sum digit to validate the data entry. As there might be multiple measurement elements or data recorders with multiple channels pertaining to one connection point, a two digit data stream suffix is used to accurately identify the data stream.

MDPs, in conjunction with MPs, have to ensure that the following are performed:

a. metering data correctly relates to the registered metering installation
b. all data streams are captured
c. NIM is correct
d. NIM is within the range allocated to the Network Service Provider (NSP) in question

For unmetered sites (type 7), the MDP must ensure that inventory tables, load tables and on/off tables which are used to estimate the metering data for these installations are complete.

All interval data must be checked against a nominated minimum or maximum value to capture erroneous data spikes. A check against nominated minimum value may be replaced by a check against an allowable number of zero interval readings based on historical data. For metering installations that support this form of validation procedure, interval meter data can be checked by comparing accumulation register readings with the change in the meter cumulative registers.

For metering installations that have check metering in place, the MDP must construct validation algorithms within the metering services database. A comparison with the check meter might require examining the nodal energy balance (sum of energy flows to and from a busbar) or the calculation of transmission losses between the main meter and the check meter. Where AEMO makes SCADA

readings available, the MDP must develop algorithms that enable a meaningful validation of metering data with the SCADA data.

While AEMO does not require that the MDPs must use specific software to validate meter data, the rules indicate that the processes have to be performed with an algorithm.

AEMOs electricity metering team consists of three people, one Metering Engineer, a senior data analyst and a data analyst. It is the data analyst's duty to perform the metering validation procedures while the two other staff members oversee his work and have other responsibilities within the settlement process.

Metering staff have no power or ability to perform any substitutions on the metering data. If errors are discovered they have to be amended by the responsible MDP.

In cases where the MDP has failed to deliver data within the required time frame, missing data is replaced with values based on pre- determined rules. The logic for these rules is implemented in the MSATS system and applied automatically.

Best Practice Recommendation

In WESM, PEMC receives metering data from NGCP on daily basis in the form of MDEF files which are uploaded into PEMC's meter data warehouse. From here the data is extracted into spread sheets to perform a set of validation procedures. Many of these validation procedures are highly reliant on the manual input and knowledge of staff.

Generally such a high level of manual input is susceptible to human error and we would recommend implementing automated validation procedures similar to the ones employed by AEMO that tie in directly with the metering data warehouse.

In our review of the process of issuing meter trouble reports we have found that many meter trouble reports are issued for so called "orphan meters". These "orphan meters" are installation for which PEMC has received data but which are not yet registered with PEMC. We would suggest that the procedures for registering new metering installations are more closely aligned with PEMC's need to be aware of such new installations.

3.2. Data Storage

In ANEM, meter data providers are required to maintain a record of all metering data in a metering data services database. Such database provides a full audit trail and version control capabilities for:

a. all metering data and standing data on NMI connection points
b. information on quality flags assigned to metering data
c. types of substitutions
d. meter alarms
e. metering register information
f. the delivery of data to AEMO, other MDPs or registered participants

In addition AEMO maintains its own metering data management (MDM) system to manage meter data history, version control and the creation of settlement ready extracts to provide settlement reports to participants.

Typically metering of a large number of sites in a high temporal resolution produces vast amounts of data that need to be properly managed. Databases provide the functionality to structure, retrieve and store data in a way that can be managed. While a wide array of database management systems exists,

all databases have in common is that they represent a structured collection of data. There is a range of generic database management system (DBMS) that can be adapted to be used in any application such as Microsoft SQL Server, Oracle or MySQL. Many commercial database management systems however include added functionalities for the specific tasks – such as metering – that they are designed to perform. While the underlying structure of the data is different between most database management systems, standards such as SQL and ODBC allow communicating between different systems.

AEMO does not prescribe a specific database management system to be used by MDPs as long as it complies with the MSATS procedure requirements.

Best Practice Recommendation

Commercial metering database management systems in use in the WESM include MV90 and POMAX.

MV90

MV90 is a meter data collection and management system developed by U.S. Company Itron. The key advantage of MV 90 is its capability of communicating with about 160 metering specifications and translating this data into the MV90 format. MV90 also includes functionality to perform data validation and estimation.

In additional modules, the software supports TCP/IP communication and ODBC access allowing for accessing the database with other data base management systems.

POMAX

POMAX is a commodity trading and risk management (ETRM) system developed by Norwegian company Navita Systems which has been bought by UK based company Brady in 2012.

POMAX Energy Data Management (EDM) supports automated collection of meter data from ODBC supported databases. Internally, POMAX runs on Oracle Database 11g R2 and Oracle Linux 5.5 or Oracle Solaris 11 Express. The EDM has features for the verification, aggregation and estimation of meter data at time of import. Estimating of missing or incorrect data can be implemented manually or rules based.

AEMO's database

AEMO has developed its own software solution for MSATS which includes MDM solution and a Consumer Administration and Transfer Solution (CATS). CATS manages NMI connection point data and the connection point address, metering register data, distribution loss factor data and other information used for market settlement. The MDM solution manages the meter data history and version control and is used to create settlement reports for trading participants (TPs). As the MDM is a database based system, this can be done through queries which can be automatically run directly from the database.

Currently PEMC employs a range of Visual Basic Applications (VBA) based programs nested in spread-sheets to perform many of the tasks such as meter data validation that software like POMAX, MV90 or AEMO's MSATS are able to do highly efficiently. An up-to-date database management system would allow performing the tasks of meter data validation, estimation, editing and substitution in a more time efficient and fail proof manner.

We note that as part of switching to a database based solution training of staff in the use of databases especially the design of SQL queries would be advisable. PEMC already has two different database solutions in operation and could choose to update, and more closely integrate either of these into its metering procedures.

PEMC has informed us that it had previously used MV90 for a range of purposes including meter data validation. After not following through with an update of the software some functions of the software were lost and eventually the software was replaced with the procedures currently in place. We would strongly recommend reinstating MV90 as there is an existing knowledge base on how to use the software within PEMC.

3.3. Data Transmission

In ANEM, AEMO has developed a customised solution for the transfer of data between MDPs and market participants. Prior to the submission to AEMO, MDPs need to aggregate any data that is in a sub 30 min resolution and transfer data into the aseXML (A Standard for Energy Transactions) standard which is used for data transmission between MDPs and AEMO.

Best Practice Recommendation

To replace a MV90-to-MV90 MDEF file transfer which had been in place since the conception of the WESM market, PEMC and NGCP have set up a file transfer protocol to transmit data from NGCP on a daily basis. On a monthly basis NGCP sends metering data to PEMC by mail using CDs for the transfer.

We note that it would be highly advantageous to reinstate the old MV90 to MV90 transfer as this would allow for a continuous update of metering data, version control and faster processing. The current process of transmitting meter data by CD is lengthy and might result in delays in the issuance of final settlements especially if meter data volumes increase.

4. Issues surrounding market rules and manuals

4.1. Classification of metering data

NEM metering installations are classified by consumption and different requirements in terms of accuracy and procedure apply to each type of installation. This allows AEMO to focus efforts on more significant metering installations. A classification of metering data can allow developing specific procedural frameworks that can be easily distinguishable.

Best Practice Recommendation

During our review we found out that in the WESM there is no formal classification of metering installations apart from generator and load meters. Especially on the load end side, a classification of metering installation by consumption could be beneficial.

4.2. Documentation of procedural framework for substitution

In the National Electricity Market of Australia, a set of clear instructions define the method of substitution to be used for any situation where metering data needs to be substituted.

Estimation or substitution of metering data is necessary where metering data has failed validation procedures or metering data cannot be obtained within the performance requirement timeframe.

Table 5: Substitution and Estimation Types
lists all acceptable estimation and substitution techniques as they are listed in AEMO's metrology procedures.

Table 5: Substitution and Estimation Types

Type	EST or SUB	Installation Type	Short Descriptor
Type 11	SUB	1 - 4	Check
Type 12	SUB	1 - 4	Calculated
Type 13	SUB	1 - 4	SCADA
Type 14	SUB	1 - 4	Like Day
Type 15	SUB	1 - 4	Ave Like Day
Type 16	SUB	1 - 4	Agreed
Type 17	SUB	1 - 4	Linear
Type 18	SUB	1 - 4	Alternate
Type 19	SUB	1 - 4	Zero
Type 51	SUB or EST	5	Previous Year
Type 52	SUB or EST	5	Previous Read
Type 53	SUB	5	Revision
Type 54	SUB	5	Linear
Type 55	SUB	5	Agreed
Type 56	SUB or EST	5	Prior to First Read - Agreed
Type 57	SUB or EST	5	Customer Class
Type 58	SUB or EST	5	Zero
Type 61	SUB or EST	6	Previous Year
Type 62	SUB or EST	6	Previous Read
Type 63	SUB or EST	6	Customer Class
Type 64	SUB	6	Agreed
Type 65	EST	6	ADL
Type 66	SUB	6	Revision
Type 67	SUB	6	Customer Read
Type 68	SUB or EST	6	Zero
Type 71	SUB	7	Recalculation
Type 72	SUB	7	Revised Table
Type 73	SUB	7	Revised Algorithm
Type 74	SUB	7	Agreed
Type 75	EST	7	Existing Table

For each type of metering installation, clear rules indicate which substitution and estimation techniques are to be applied under which circumstances. The explicit definition of these rules allows for a clear auditable procedure to be applied by each MDP. The algorithmic implementation of each substitution or estimation technique is also clearly defined for each of the 30 techniques. For illustrative purposes, please refer to Appendix 1: Preferred Substitution Method for Type 1 – 4 Metering Installations

We note that the rules, in place in the ANEM, regarding allowable substitution and estimation techniques are laid out in a manner that allows MDPs to implement algorithmic procedures to apply these techniques. As a result manual intervention in the process is only necessary where an agreement between the market participant, the NSP and retailer on a certain method has to be found. The data quality flags raised throughout the process allow keeping track of any changes in metering data and make the overall process logically reproducible and efficient.

Best Practice Recommendation

The metering manual in place in the WESM lays out a number of acceptable procedures for the substitution of data. However, there is no clear schedule of which technique is to be applied in a specific circumstance. In our discussions we found out that while the official manuals do not include a formal hierarchy of procedures to be applied in each case, metering personnel follow an informal hierarchy. The appropriateness of each substitution technique is discussed with the affected TPs in a face to face meeting which prolongs the resolution of metering problems.

Ultimately, a formal list of substitution procedures to be applied in each case could allow for the automation of the process. If the procedures are laid out in a very precise way, it could be translated into code and a computer program which could automatically implement the procedure and produce a brief substitution report to inform the metering personnel of the substitutions that were made.

In our discussions with PEMC staff we have been informed that PEMC is working on a revised metering manual which will include the specific order in which estimation procedures are to be applied. In our understanding, the current list, in order of preference, are as follows:

a. If four or less intervals are missing, the missing data is to be interpolated
b. For more than four missing intervals, data from a backup meter is to be used
c. Estimation using a power formula of VI cost data
d. Good (i.e. validated) RTU data
e. Use an average of the same time intervals of the last three days with valid meter data

We recommend that this revised manual takes into consideration the level of precision that would be required to automate the process. We note that automation of the process might not be possible in the short term but that a detailed manual could lay the foundation for the implementation of such a process supported by robust system.

5. SSLA Calculations

5.1. Possible Simplification of SSLA Calculations

We note that in some well-functioning markets such as in Australia, the treatment of losses is highly simplified. In the wholesale market, within a single large region (equivalent to Luzon, for example), prices vary only by a constant loss factor. Loss adjustments between the point off-take and consumption or generation are constant factors which are adjusted on a yearly basis. The reason is that the loss of efficiency from the small pricing errors introduced by this approach is not considered to be serious enough to warrant greater complication in implementation. The annual process is much less demanding and less prone to error.

In the Australian market, similar approximations to calculate losses within the distribution network are used for settlement purposes.

A further factor particularly relevant in the Philippines is that much larger pricing discrepancies are introduced by rules that adjust for extreme price variations arising from network constraints.

These factors suggest that a move to simplify the process by using fixed loss adjustments, or loss adjustments that depend only on system configuration, is worthy of consideration. BSMD is currently reviewing such an approach. The suggestion that follows generally assumes that dynamic Site Specific Loss Factors (SSLF) will be retained, but would still apply even if there were a move to constant or configuration-dependent factors.

5.2. Improved SSLA Processing

The current SSLA prices are carried out in spreadsheets and require s much manual intention to run and maintain. A degree of macro automation is implemented to loop through the hundreds of spreadsheets for processing, but much manual setup is still required.

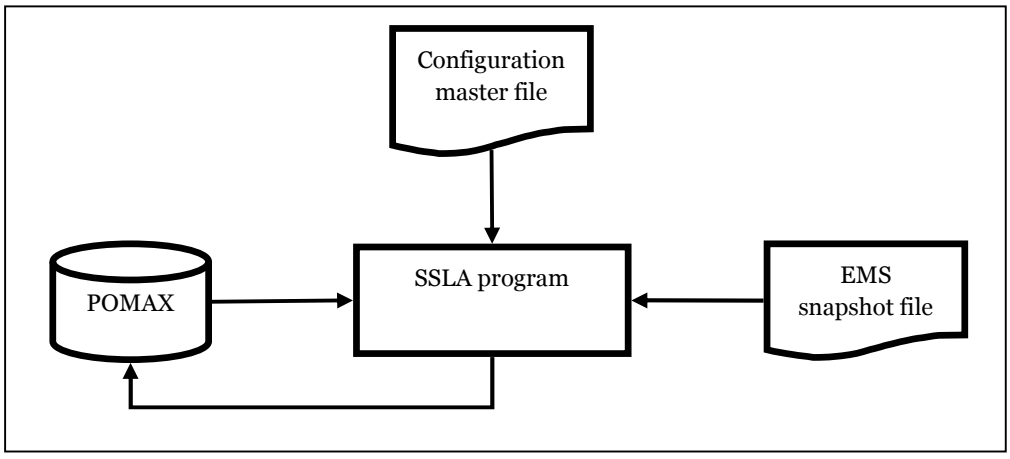
Some idea of the complexity of the process can be gauged form the Metering Manual. The basic engineering and loss allocation relationships are relatively succinct and are summarised on one page in Section 9.8.3 of the manual, with another few pages for definitions. Section 9 on the SSLA also outlines 9 different configurations to which these relationships would be applied. There are 35 pages of Appendices (from page 170 of Version 7 of the Manual that detail densely packed equations the implement these configurations, the number expanding further to reflect how the network has been switched.

The complexity here arises from the fact that each configuration has been solved manually in advance, and is then manually coded in individual spreadsheets. A much better model is to develop and maintain a single code base that can process any configuration given to it. While the 35 page Metering Manual appendix referred to above suggests that this could be very difficult, the implementation we propose would looks more like the single page of core relationships described in the Section 9 of the body of Manual.

The key feature of the proposed new architecture is a complete separation between data, model configuration and parameters, and model processing. All data would be handled in databases (although it may be delivered in various other forms) and the processing would be in a language such as MATLAB. No spreadsheets would be required. Using MATLAB or a similar high level language, a prototype system could be developed and tested for workability very quickly and cheaply.

The main features of an integrated and more robust SSLA system are outlined on the figure below.

Figure 6: Integrated SSLA System



Elements presented on Figure 7 are:

Configuration master file

This configuration file would replace existing MTN Mapping template files. It would contain information on the mapping between metering points and the MTN they are allocated to. For each MTN, information would include:

- the list of devices connected or allocated to it including: conductors, transformers, circuit-breakers, and metering points,
- the parameters associated with these devices and required for loss adjustment calculations,
- the way devices are connected; and
- information describing additional rules for allocating losses to metering points.

Circuit breakers are modelled in a specific configuration and may have a state of open or closed. This state would be driven by an external file (the EMS snapshot file or alternative). Unlike the current setup, no additional configuration files are required for different switching states.

While the configuration master file contains device parameters and connectivity information, unlike the MTN mapping template files it contains no processing information. Processing is carried out "on the fly" in the SSLA Program.

We envisage that these data would be managed by a graphical application, possibly web based, where the configuration could be directly visualised and data managed in that context. The SSLA program would also be managed and launched from this interface.

POMAX

The SSLA application would interface directly with the POMAX (or replacement) database to collect meter data and to return results (loss adjusted quantities and SSLF). This would reduce the large number of intermediary files required by the current system. A separate reporting application could be developed to extract adjustment results if required for participants or settlement.

EMS Snapshot file

Energy Management System (EMS) snapshot file: statuses for circuit-breakers would be processed by the SSLA Program to determine "on the fly" which mapping configurations applies at any given time.

In the absence of such information (which is not available at present), the file would contain output of the manual process that maps metering points to MTNs as circuit breakers are opened and closed.

SSLA Program

This program, probably written in a high level matrix language such as MATLAB, would implement the following processing logic:

- For each MTN/meter group, read in and construct the network configuration information from the configuration master file ,
- For each time period, read in the corresponding meter data
- For that time period, read in and set the circuit breakers in the model
- Construct the set of (nonolinear equations to be solved; equations include relations between input and output for each device, power balance equations, additional constraints to define allocation rules, etc.
- Solve the equations using a general procedure such as Newton's method
- Recover the solved result for flows through the MTN allocated to each meter,
- Write the adjusted values and corresponding SSLF to the POMAX and/or other files
- Repeat for each time step (noting that the configuration only needs to be set up once, subject to adjustments if switching occurs)
- Repeat for each MTN/meter group.

The SSLA program would also include integrated or perhaps separate pre and post-processing and would contain a range of error checks at those stages to ensure a clean final run through the system.

6. Metering Installation Industry Best Practices

6.1. On Communication Link

While the Digital Telephone System (DTS) and the Global System for Mobile (GSM) are the only communications network systems adopted in the Philippines for meter data transmission, the **National Electricity Rules (Version 50) of Australia** provides for the following methods of remote meter data acquisition:

a. Fixed-line telephone or direct dial-up;
b. Satellite;
c. The internet;
d. Wireless or radio, including mobile telephone networks;
e. Power line carrier; or
f. Any other equivalent technology.

Taking into consideration the other major factors to be considered in the application of the most suitable communication link such as the performance of the communications medium, the costs associated with the installation and maintenance and the individual location of the metering facilities and their environment, these communications systems come in different advantages and challenges. With the available resources that may be utilized by the Metering Services Provider, a conduct of study in the selection (retention and enhancement of the current facilities or transformation to another predominant technology) of the most applicable communication link is recommended to properly manage the communication problems currently encountered in remote meter data acquisition.

Incidentally, the **Metering Best Practices Release 2.0 of the U.S. Department of Energy Section 6.2 Modern Communications – Automated Meter Reading (AMR)** provides for some of the predominant AMR technologies similarly acceptable in Australia and the Philippines as all of these facilities enable metering data to be transmitted from the metering installation to the metering database:

6.1.1. Phone Modem

Taking advantage of telephone modem technology in both hardwire and wireless (i.e., cellular), this communications solution is the oldest and traditionally most reliable of the technologies. In typical applications, automated software is used to dial or phone-in the modem daily to retrieve accumulated data. In addition to the phone-in systems, there are meters that can phone-out at preset times or at specified data accumulation levels. It should be noted that phone lines do not have to be dedicated to the meter(s) they serve; there is no reason that meters cannot share a phone line with other applications – even personal office phones. Shared phone line applications can use off-hours for data communications and, therefore, do not interfere with other business-related uses.

6.1.2. Local Area Network

Using an existing building or site's computer network to serve as the communications path for the metering system can be very economic. When properly configured, meters can communicate over this network using a variety of open protocols (e.g. transmissions control protocol/internet protocol or TCP/IP, etc.) In addition, these meters usually can be serially addressed and linked together (daisy-chained to minimize wiring installation and expense.

6.1.3. Building Automation System

By using an existing building automation system (BAS), an advantage of a site's previous investment in existing infrastructure may be utilized. In this case, the wiring used for BAS communication becomes the metering communications path. The meters are treated as other "points" on the BAS and function much as other sensors or points on the system (i.e., communicate to and from the central host computer). The BAS is a workable solution only when there is excess capacity to add points and system software is capable of using the meter's data output protocol – both of these factors need be verified with the BAS and metering equipment vendors. An additional constraint to the BAS solution relates to the host computer's ability to allocate memory for these data and offer an ability to retrieve data sets in an automated fashion.

6.1.4. Radio Frequency/Wireless Networks

Becoming increasingly available and economic, wireless radio frequency (RF) communications makes use of wireless transmitters and receivers to communicate metered data. Wireless communication offers the benefits of lowered installation cost, flexibility in metering locations, and minimizes disruption in service when compared to other options. Some of the limitations to wireless communications include the effective distance of communication (typically less than 300 feet) and the metering facility's materials of construction that may impede or block the RF signal. Similar to the LAN solution, wireless communications has perceived challenges including security issues and potential for interference with other sensitive communications equipment.

6.1.5. Power Line Carrier

This technology uses existing electrical wiring, both internal and external to buildings, as the communications conduit. While making use of the existing infrastructure gives this technology and economic advantage, limitations related to speed and quantity of data transfer and the ability to transfer data across standard electrical transformers can occur. Organizations making productive use of this technology, notably utilities and sites with many distributed buildings, do so by spreading the considerable installed cost over many metering points, or utilizing available communications technology that overcome this barrier.

6.2. On Meter Seal Issuance and Removal Procedures

The MTD currently does not practice monitoring of meter seals upon issuance or retirement. It is recommended to adopt stricter procedures on providing personnel of the seals during fieldwork and recording of mutilated or retired meter seals from equipment.

6.2.1. Listing or Database of Meter Seal Users

There should be a listing of meter seal users or assigned personnel from the MTDs allowed to use meter seals during fieldwork. The listing should be updated monthly, with the information sent by the MTD to the central warehouse or repository issuing the meter seals.

6.2.2. Issuance of Meter Seals to the MTD Personnel

The responsible department for the central custody of the meter seals should adopt a monitoring document for issuance of meter seals, indicating the name of personnel and assigned serial numbers. The document should be signed in three (3) copies by the responsible department for the seals, personnel assigned to the seals and MTD Head. This document should be sent to department responsible for the seals for updating the database of meter seal issuance.

The monitoring document being signed by the user of the seals should be issued in advance prior to actual issuance to check whether the assigned user is recognized by the MSP.

6.2.3. Retirement of Meter Seals

Upon removal or retirement of meter seals, the user or personnel assigned to issue new meter seals should record the mutilated seals in a separate monitoring to be submitted together with the retired seals. The monitoring of retired seals should be encoded in the database to update the retirement of seals.

6.3. On the Responsibility on Meter Seals

The current procedures regarding meter seals in the MSP does not explicitly state the responsibilities of the Trading Participant, MSP and MO. The Trading Participant, MSP and MO can be a person responsible to the meter seals attached to the metering equipment. A set of procedures can be applied to identify who will be responsible in cases where seals are broken or removed without proper authority.

As practiced in a similar energy market, whenever seals are broken, the responsible person is notified by a person who discovered the broken seals. This person can either be the MSP, Metering Data Provider or Market Participant. A maximum number of days to notify the responsible person should be implemented to formally transfer and identify the responsible party for the broken seals.

The notification to the responsible person of the broken seals previously attached to the metering equipment should be in a written format, coming from the person or party who discovered the incident. Once identified, the broken seals should be replaced by the responsible person within an allowable period of time.

It may be applicable to have the meter seals replaced, as being practiced in a similar energy market not later than the first occasion on which the metering equipment is visited to take a reading. The allowable period of time for replacement can also be within 100 days after receipt of notification by the responsible person within 5 business days.

Furthermore, the cost of replacing the seals should be borne by the responsible person, since as a result of breaking or removing the seals, the equipment does not meet the minimum requirements provided by the MO.

6.4. On changes in settings or parameters in Meter Installation

The changes in metering installation should also include updating the metering register of the MO. The changes should include changes to metering equipment, parameters and settings within a metering installation.

To immediately provide the MO of the changes in metering installation, as practiced in other similar energy markets, the alteration or changes are requested by the MSP prior to adopting the change. The MO authorizes and issues an approval document allowing the change or alteration within a specified period of time. As practiced in a similar energy market, the MO notifies acceptance of changes and authorizes the MSP within two (2) days.

Furthermore, the change or alteration should only be made by the MSP. In such cases where the MSP does not have the capability of conducting the required changes, a responsible person can be nominated and presented to the MO for approval.

Once allowed, the MSP should notify the MO about accepting its decision whether authorizing the MSP or not of the change, within two (2) days, as practiced in a similar industry. Upon receipt of the document recording the changes conducted by the MSP, the MO records them in the metering register.

7. Issues surrounding preventive maintenance activities and responsibilities

WESM-MSDM-MM-07 Metering Standards and Procedures, Metering Service Agreement, Article 3-MSP Rights and Obligations, clause 3.3-Provision of Metering Services requires the MSP to provide preventive maintenance services on metering installations which includes:

- Meter reading
- Periodic inspections
- Metering security
- Meter data communications service
- Annual calibration and testing of meters
- Testing of instrument transformers

On the other hand, article 4-Rights and Obligations of Metered Trading Participants, clause 4.3-Payment of Metering Charges requires the Trading Participants to pay the MSP, as regular monthly charge, covering the costs of such preventive maintenance services.

Similar standards in other competitive electricity markets have the same definition of MSP's rights and obligations. AEMO Metrology Procedure, section 1.4-Responsibility for Metering Provider services, and Australian National Electricity Rules (NER) version 50, section 7.4.1-Role of Metering Providers briefly states that the Metering Provider should undertake the tasks of installation and maintenance of metering installations.

However, current practices on preventive maintenance, especially on instrument transformers, are primarily based on the ownership of the metering equipment. As the MSP is routinely performing preventive maintenance activities on equipments owned by them, the case is not always the same for those owned by Trading Participants/Customers. The MSP would not conduct any testing on Customer-owned equipments unless there are formal requests from concerned Customers.

Best Practice Recommendation

Since the Philippine WESM Rules and Manual are at par with similar standards in other competitive electricity markets in terms of defining the requirements for preventive maintenance activities, strict enforcement and performance are keys to ensure compliance with these requirements.

NGCP, as the MSP, should ensure that these preventive maintenance services are being performed in compliance with the corresponding WESM requirements; while PEMC, as the Market Operator, should strictly enforce these requirements to the Trading Participants/Customers.

Clear-cut guidelines on responsibilities among the MSP, Market Operator and Trading Participants for preventive maintenance activities should be further defined in applicable provisions of the WESM Rules and Manual regardless of the ownership of metering equipments.

Also, it should clearly define responsibility and accountability on maintenance of overall premises of the metering site (i.e. setting-up of perimeter fences, management of vegetation growth, etc.) to ensure other external factors are considered in maintaining the metering facility.

To further facilitate compliance, additional provisions in the WESM Rules and Manual should include applicable penalties and sanctions for those Trading Participants who will not comply with these requirements. This is to ensure that Trading Participants will also be more diligent in maintaining metering equipments owned by them.

Section 1: Engagement Overview

Pursuant to Wholesale Electricity Spot Market (WESM) Rules 4.5.5.4, Philippine Electricity Market Corporation (PEMC) Audit Committee engages the services of Isla Lipana and Co., a member firm of PricewaterhouseCoopers, in partnership with Alliance of Power and Energy Xponents (APEX), Inc. and Intelligent Energy Systems (IES) to review the adequacy and compliance with the requirements of the metering installations under the WESM Rules and related manual taking into consideration the following:

a. Best Practices in other competitive electricity markets

b. Available technology and its cost

c. Actual performance in relation to:

   i. Timeliness of addressing Meter Trouble Reports (MTR)
   ii. Adequacy and conformance to good utility practice of preventive maintenance performed on metering equipment, including completeness of maintenance programs, test results and sealing records.
   iii. Availability and reliability of the meter communication links and interfaces to the meter data collection system of MSP
   iv. Adequacy of the software and programs used by the MSP in meter data collection, metering database and data validation
   v. Adequacy of the process use by the Market Operator (MO) in estimation and editing of meter data
   vi. Reliability of communication link and interfaces between MSP and MO
   vii. Adequacy of remote monitoring facilities to alert the MO of any failure of any component of the metering installation
   viii. Adequacy of physical security provided to the metering equipment
   ix. Adequacy of physical and logical access security provided to metering data held in metering installations and to the corresponding database
   x. Availability of recovery plan and procedures in case of erased or corrupted metering data and of an offsite data storage location
   xi. Security of meter data during transmission and receipt between the MO and MSP
   xii. Accuracy of metering installation based on test results
   xiii. Availability of spare parts in case of defective metering installations that needs immediate replacement
   xiv. Availability of check meters for WESM main meters
   xv. Appropriateness of the revenue metering and market trading node location (MTN)
   xvi. Accuracy of the results of the Site Specific Loss Adjustments (SSLA) calculations

The review covers Luzon and Visayas metering sites registered in the WESM from December 26, 2011 to December 25, 2011. At least 180 of the metering sites with the largest volume within the WESM and at least 36 of the metering sites identified by the PAC and Metering Arrangement Review – Technical Working Group (TWG) were inspected.

Section 2: Methodology and Approach

Completion of Initial Mobilization

1. Inception reporting

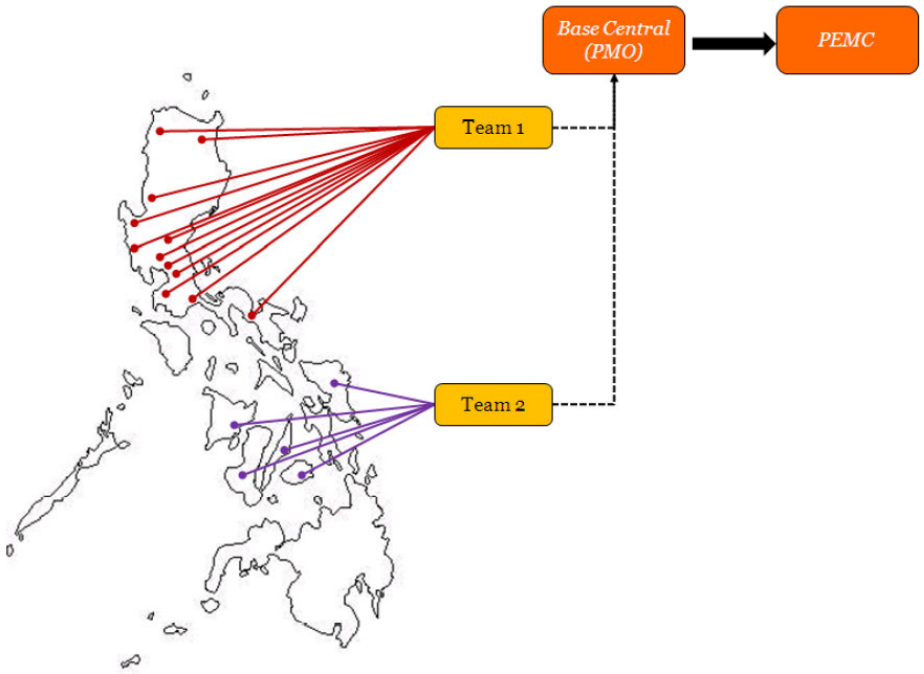
Prior to actual team mobilization and execution, a Metering Review Process Workshop was conducted to ensure that the objectives, scope and methodology of the metering review were understood clearly across the review participants, namely: PAC, PEMC Board, MSP, Energy Regulatory Commission (ERC), GMC, DMC, TransCo, Technical Committee and other key stakeholders.

An Inception Report was distributed to key stakeholders that contained PwC's Review Plan, Assumptions, Methodology and Work Program. This confirmed the review scope and outlined the review approach, including the review process, schedule of proposed client interaction during the duration of review work, among others. The Inception Report was agreed upon by the PwC, PAC and the Metering Arrangement Review – TWG.

2. Resource Plotting and Logistics

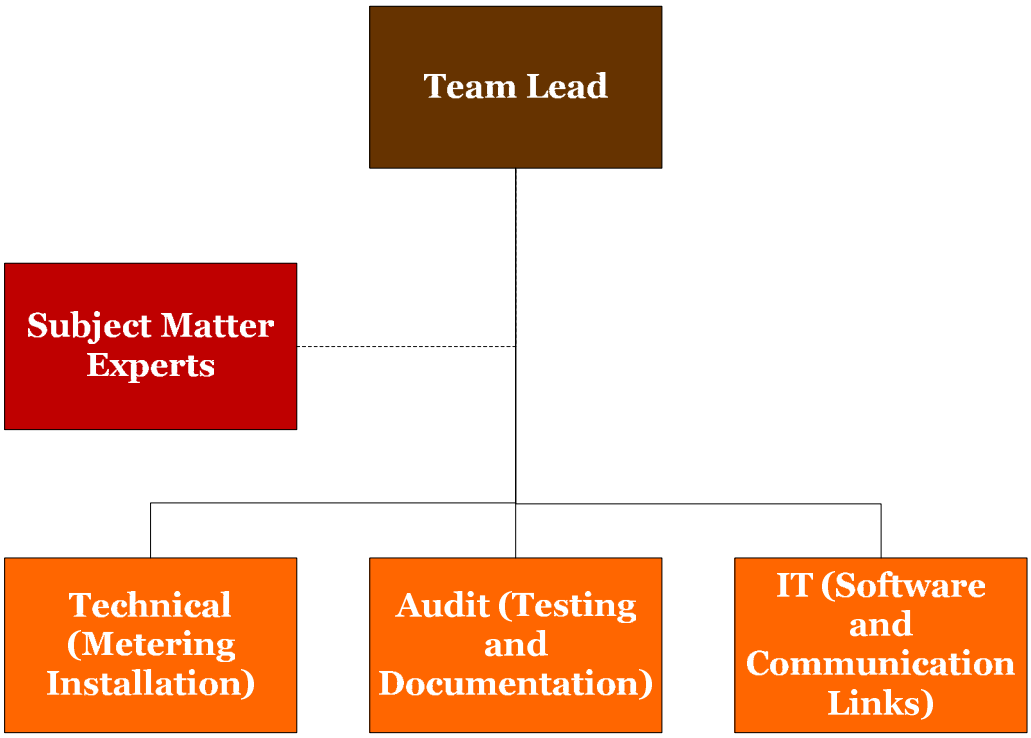
Project teams were strategically grouped accordingly to cover the different metering sites in a most efficient manner based on geographical location. There were two (2) project teams which were centrally reporting to the Base Central or PMO (PEMC Head Office in Ortigas, Pasig City). The Base Central was in-charge of reporting and coordinating the progress of the project and communication of major and critical issues to the PAC during the fieldwork.

Figure 7: Resource Deployment / Plotting



Each project team deployed in the various metering sites were generally composed of four (4) key resources namely, the Team lead, Technical Metering resource, Audit resource, and IT Communication resource, all of whom performed various roles related to their field of specializations.

Figure 8: Review Team Hierarchy



3. Project Deliverables

Aside from the Inception Report, the following documents were also delivered to PEMC-PAC:

a. ***Progress Reports*** – These reports highlighted the status and relevant developments of the review activity. The reports were submitted every two (2) weeks from the start of the engagement up to the conclusion of the review. The following Progress Reports were submitted to PAC:

Table 6: Progress Report Submission Schedule

Activities	Date Submitted
1st progress report	September 5, 2012
2nd progress report	September 14, 2012
3rd progress report	September 28, 2012
4th progress report	October 15, 2012
5th progress report	October 29, 2012
6th progress report	November 10, 2012
Final progress report	December 7, 2012

b. ***Significant Issues Report*** – This report covered identified inconsistencies, or non-compliances of the systems and procedures under the WESM Rules and related Manuals and relevant provisions of the

Philippine Grid Code, whenever referred to by the WESM Rules. One Significant Issues Report was issued on November 10, 2012

c. ***Draft and Final Review Reports*** – These reports provided among others the review methodology, findings and observations, summary of comments and recommendations, identified non-compliances and recommendations.

4. Inspection Methodology

a. ***Documentation Audit –*** covered the review of relevant documents, records and reports being used in the metering process such as actual Meter Trouble Reports, Metering Installation Registration Forms (MIRF), etc., to ensure compliance to the WESM Rules and related manuals.

b. ***IT General Controls Audit –*** focused on reviewing the reliability of the data collection capabilities of the communication links and the different software or application programs being used in the metering process.

c. ***Meter Process Audit –*** covered the different test procedures to primarily ensure the reliability and accuracy of metering registration, installations, calibration, maintenance and other related processes. This also included the security measures (both physical and logical) currently in place at the various metering sites.

d. ***Meter Integrity Audit –***entailed a more comprehensive and rigid approach which focused on the identified 36 critical and significant sites. This included actual on-site testing and verification of the meter's performance using widely-accepted procedures and use of ERC-certified meter testing devices and equipments. The review team considered either Energy Standard-based (ERC Recommended) or Portable working Standard (PWS) methodology.

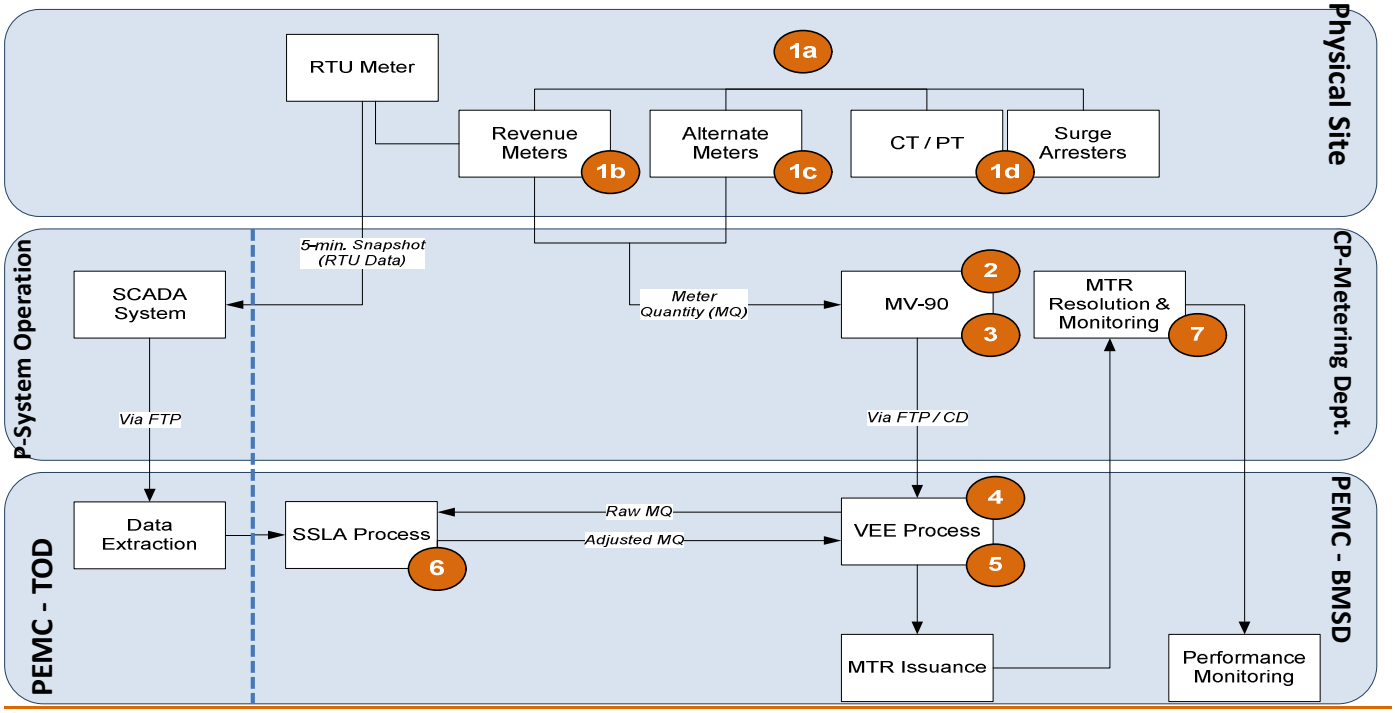
e. ***Best Practices Recommendation –*** ensured that our inputs were valuable and included recommendations beyond compliance. This covered recommendations and perspectives of best practices from other competitive electricity markets.

This component is essentially a desk operation that was conducted off-site. However, it was guided mostly by specific issues or problem areas that were noted during the review period.

Please refer to *Appendix 14: Mapping of Test Procedure and Audit Requirement* for detailed procedures performed vis-à-vis the different audit requirements per RFP.

Quality Execution

Figure 9: Review Team Assignment



No.	Activity Description
Meter Site Visits	
1a	Overall environment & security conditions of metering sites
1b	Physical inspection & meter integrity testing (as applicable) of main revenue meters
1c	Physical inspection of alternate meters
1d	Physical inspection over instrument transformers
Head Office (NGCP and PEMC)	
2	ITGC review over MV-90 & other relevant systems
3	Systems & process review over MV-90 and related applications
4	Systems & process review over VEE
5	Review over spreadsheets used in VEE process
6	Systems & process review over SSLA calculation
7	Process review over MTR resolution and monitoring

Each team deployed were provided with their respective audit checklist and inspection plan which details the different audit activities and test procedures performed. This was to ensure that all required audit objectives ware covered by the project teams simultaneously in a structured, most effective and systematic manner. Also, the audit checklist ensured standard and consistent performance of tasks between teams.

Broadly, the team utilized relevant practice aids, knowledge resources, and IT software assessment tools and programmed spreadsheets. For efficiency, results of the review and test procedures were centrally documented using proprietary electronic working papers.

a. Review of the VEE – related processes

The review team identified the processes undertaken in the VEE and the persons responsible for the process. We reviewed MTRs and other complaints register for clues or indications regarding problem areas in the VEE process and metering in general. Broadly, we reviewed the scope of the validation checks and their completeness, relevant good practices used in other electricity markets.

Additional procedures were performed as applicable, including:

- Review of the software such as macros and procedures used to implement these checks and validation
- Review of the estimation procedures used, processes used to calculate the estimations
- Analysis if the editing procedures used where required to fill in data
- Review and identification of opportunities for improvement for resourcing and timing performance.

b. Assessment of the metering node / location

The first level of review was associated with the physical site inspections, where such an inspection takes place. We evaluated opportunities for metering location such as closer to the MTN or, in more complex cases, where estimation might be made simpler and more accurate.

Secondly, we assessed if the checks to ensure that the market nodes defined in the settlement process were properly represented in the WESM dispatch and pricing model. This may be guaranteed by the processes employed, however, we have included in the review to confirm propriety.

c. Accuracy Testing of SSLA Calculations

We reviewed the code that implements the SSLA calculations and procedures associated with the management and use of these spreadsheets. We also offered advice on the scope for better practices in this area. The general approach was proposed as follows (not every element was able to be completed in the same detail):

- Reviewed and commented on the SSLA versus those performed in other similar markets, if any.
- Reviewed dispute history and resolution, if relevant
- Reviewed the engineering calculations contained in the metering code for reasonableness and accuracy
- Reviewed adequacy of data sources and how they are managed and secured. Specifically, we reviewed whether each configuration was available in some standard format.
- Verified the operation of the spreadsheets by reviewing calculations cell by cell in a small sample of specific cases.
- Developed an independent SSLA calculation logic and compare the output of each using identical inputs; identified and explained any differences.
- Reviewed the security and data integrity controls and practices implemented in the spreadsheets and whole SSLA process
- Commented on proposed changes that would make Site – Specific Loss Factors constant for any specific mapping of revenue meters to MTNs

Definition of Levels of Non-Compliances

The level of non-compliance as per Terms of Reference is as follows:

a. **Critical noncompliance** - a non-compliance which results in failure to provide services or results in time, or to calculate information in accordance with the WESM Rules, or to provide data in the format and/or to the accuracy required, and which results in a breach.

b. **Major noncompliance** - an occurrence, practice or deficiency in a system or process, which has the potential to escalate to a level at which it would become a critical non-compliance.

c. **Incidental noncompliance** - a condition or situation that does not qualify as critical or major, and which typically is associated with a lack of attention to detail, or lack of adequate staff training that leads to unnecessary mistakes.

Applicable WESM Rules or related provisions may pertain to WESM rules, related manuals and relevant provisions of the Philippine Grid Code. Note that these definitions will only apply to those items assessed as explicit non-compliances to the provisions of the WESM Rules and related manuals.

Section 3: Non-compliances to WESM Rules / WESM Manual

Major Non-compliances

Meter Seals Provision (MI – PI12)

WESM-MSMD-007, Section 2.9.1 – Physical Security of Metering Equipment states that metering installations shall be secured and tamper proof and conforms to the security requirements of Section 2.9.1.3 – Secondary Terminal Boxes and Section 2.9.1.6 – Meter Seals and Padlock.

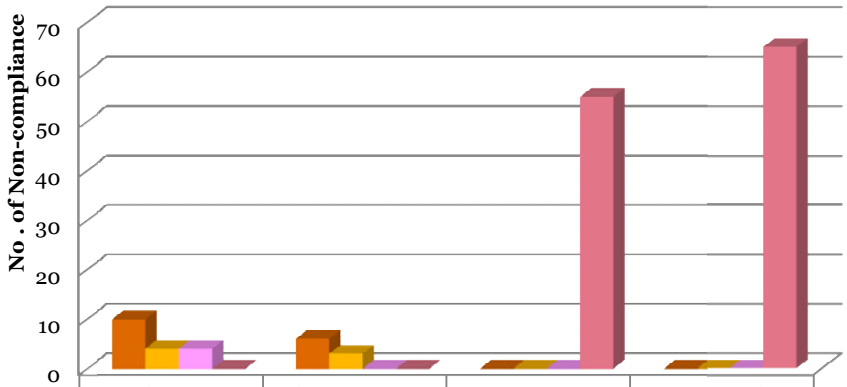
WESM-MSDM-007, Section 2.9.1.3 Secondary Terminal Boxes, Secondary terminal boxes of the current transformers and voltage transformers shall be sealed and placed as far as practicable to ensure the detection of unauthorized access to the instrument transformer connections.

Also, one of the minimum requirement for CT/PT Security as per WESM-MSDM-007, Section 2.5.7 Current Transformer and Section 2.5.8 Voltage Transformer is that seal holder should be provided to the terminal boxes. This is also mandated by Grid Code 9.4.5 Meter Equipment Security.

Observation

The following meter installation components are noted to have no seal provisions:

Figure 10: Number of Meter Installation without Seals



	Main Meter	Alternate Meter	Current Transformer	Potential Transformer
Meter Terminal	10	6	0	0
Demand Reset	4	3	0	0
Test Block	4	0	0	0
Secondary Terminal Boxes	0	0	55	65

Risk Implication

Absence of seals indicates that unauthorized persons may access the metering installation components undetected. This poses risks that the data generated by the meters may be compromised, thus may affect the accuracy of the meter quantity transferred to MV90.

Commendable Practice

We would like to highlight that the MTDs for Laguna and Daraga, to comply with the WESM rules, have performed modifications on the secondary terminal boxes so as to allow the installation of Meter Seals.

Recommended Practice

To ensure that meter components are completely installed with seals, we recommend the following:

a. A monitoring database should be developed which lists all the metering installation registered under WESM with its complete details such as serial numbers, type, make, latest PM, seal number installed, etc.
b. Every time that there are changes to any detail in the metering installation, a standard form should be accomplished, approved by the MTD and forwarded to the person responsible on maintaining the database.
c. Before subjecting the metering installation to PM activities, a report should be generated from the database showing the latest detail of the meter components. The values in the report should be compared to the "as found" details in the site.
d. If there are discrepancies in the report vs. "as found" details, an investigation should be made. These discrepancies may be an indication that changes have been made to the metering installation without proper documentation or by an unauthorized person.
e. A monitoring of the frequency of seal changes should also be performed on a regular basis. At a minimum, seals should be changed once a year, preferably every PM date. A seal change made a number of times in a single year may indicate problematic meter installations. This may also indicate that the meter is accessed frequently, which may indirectly affect its functionality.

Management Comments

We noted the recommendation but we want to emphasize that there are other security measures that will prevent tampering of the meter installation.

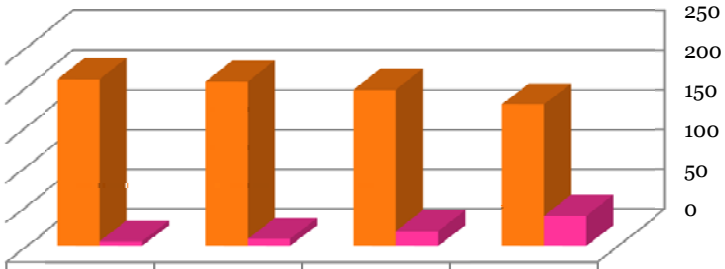
Perimeter Security (MI – PI17, MI – PI18, MI – PI19 & MI – PI20)

WESM-MSDM-007 Metering Standards and Procedures, Section 2.9.1.7 Metering Perimeter, requires that the Metering Installation shall be secured by a perimeter fence, and its gate properly padlock, sealed and secured. Metering perimeter shall also be well lighted and free from any unwanted materials, equipment, vegetation, etc.

WESM-MSDM-007 Perimeter Fence illustrates that the perimeter fence required should be at least 0.6 Meters in height. Furthermore, there are minimum clearances at the Perimeter Fence and protective clearance between barriers and live parts inside the installation.

Observation

Figure 11: Results of the Perimeter Security Check



	Perimeter Fence	Surface grade type	Illumination	Vegetation
Compliant Sites	210	207	197	178
No. of exceptions	6	9	19	38

Perimeter Fence
4 out of 216 (1.08%) metering installation have no perimeter fence while 2 out of 216 (0.92%) are broken down.

Surface Grade Type
9 out of 216 (4.19%) metering installation uses Bermuda grass or concrete instead of gravel.

As per industry practice, it is ideal to use gravel since it provides additional ground protection to the personnel (Touch and Step Potentials), prevents vegetation growth and absorbs oil deposits which can result to oil slips.

Illumination
19 out of 216 (8.8%) metering installation are not well-lighted.

Vegetation

38 out of 216 (17.59%) has uncontrolled vegetation.

Risk Implication

Perimeter security is one of the controls which ensure that the following are implemented:

a. protection against unauthorized physical access
b. the health and safety of the staff and persons around the perimeter is not compromised
c. assurance over the integrity of meter data
d. meter installation is properly maintained

Absence of such controls pose risks that the operational efficiency of the metering processes are compromised.

Recommended Practice

MSP is recommended to perform the following corrective actions:

a. immediate installation of perimeter fence on the sites.
b. use gravel on the sites.

c. provide adequate lighting installations within the perimeter area.
d. remove the presence of vegetation.

To ensure that these instances will not recur, we recommend for the MSP to implement the following:

a. MSP should agree on the roles and responsibilities pertaining to removing unwanted objects and vegetation in the different sites.
b. Perimeter security should be included in preventive maintenance activities
c. Resolution monitoring of the findings noted in the PM activity should be established.

Management Comments

We noted the recommendation but we want to emphasize that there are other security controls in place.

Incidental Non-compliances

Adjusted Loads Vs. Site Specific Loss Factors (PEMC – SSLA02)

WESM Manual 9.4 Loss Factor which states that there shall be a Site-Specific Loss Factor (SSLF) distinct for every Metering Point and dynamic for every Trading Interval, which represents the adjusted meter data of the Metering Point. The SSLF is a unit-less number that shall be multiplied to the original meter data of its corresponding Trading Interval. The end-product of the SSLF and the original meter data is the adjusted power or energy of the Trading Participant as seen from the MTN.

WESM Manual 9.7.3.1 also states that the Market Operator shall calculate the SSLF in accordance with the procedure using Microsoft Excel.

Observation

In the monthly SSLA results provided, the review team have identified a number of meters for which expression (4) on the discussion in the *Current Practice* below does not hold. The list of IDs for these meters is given below.

g. MF3MBOHBLCI03
h. MF3MBOHBOH104
i. MF3MGARPMSC01
j. MF3MUBABOH201
k. MF3MUBABOH205
l. MF3MUBAMARC01

For each of these meters, the loss adjustment calculated by the SSLA program always follows expression (2) which seems to indicate that these meters are located upstream of their allocated MTN. However, the expression used to calculate the corresponding SSLF is expression (5) instead of expression (6).

As a consequence, equality (3) Adjusted_kWh_Value = SSLF * Raw_kWh_Value never holds for these meters. Please refer to Appendix 6: Adjusted MQ vs. SSLF for details of the inconsistencies noted by the review team.

Risk Implication

If the error is in the SSLF and if SSLF is not used to adjust raw measured loads, incorrect SSLF will have no impact on settlement calculations. Therefore the only implication is an issue of non-compliance with the Metering Standard and Procedures Manual. If the errors are in adjusted values and these values are used for settlement, the error would have persisted into settlement in these cases.

Current Practice

In the majority of cases, metering points are located downstream of the MTN they are allocated to. The loss adjustment computed by the SSLA procedures can therefore be expressed as follows:

Adjusted_kWh_Value = Raw_kWh_Value + Total_kWh_Losses (1)

Where Total_kWh_Losses is calculated by the SSLA program and represents the amount of real power lost between the metering point and its MTN.

However, some metering points are actually located upstream of their MTN. With such configurations, the loss adjustment computed by the SSLA procedures can be expressed as follows:

Adjusted_kWh_Value = Raw_kWh_Value - Total_kWh_Losses (2)

In all cases, the SSLA procedures are also required to compute the SSLF so that the following expression holds:

Adjusted_kWh_Value = SSLF * Raw_kWh_Value (3)

Therefore in all cases (except when Raw_kWh_Value = 0), we should have:

SSLF = Adjusted_kWh_Value / Raw_kWh_Value (4)

And by substituting Adjusted_kWh_Value we should have:

SSLF = 1 + Total_kWh_Losses / Raw_kWh_Value (5)

When a meter is downstream; and

SSLF = 1 - Total_kWh_Losses / Raw_kWh_Value (6)

If a meter is upstream of its MTN.

Recommended Practice

SSLF computation formulae for the meters listed in the above observation should be reviewed and fixed. The error observed here supports the audit recommendation to improve SSLA processing.

Management Comments

BSMD has reviewed the specific cases identified and has acknowledge that there is an error in the spreadsheet master files, as outlined in the two paragraphs that follow. They report that the SSLF calculation was correct but there was an incorrect sign in the loads adjustment formula. The error has now been corrected.

As per official comments sent on November 29, 2012:

During the start of Visayas WESM, the loss adjustment computation for SSLA or adjusted_kW_Value = Raw_kW_ Value + Total kW Losses. However, the MTN 7UBAY_T1L1 was re-modelled when an embedded generator was included in the settlement. The re-modelling aims to subtract the adjusted meter data of a nearby Generator to the load/meter nearest to it. Since it is impossible that all of the dispatch of the Generator as read in its meter would reach the metering point of the nearby load, line losses were deducted from the raw meter data of the Generator. However, the subtraction equations were accidentally got copied in the other cells below where the adjusted meter data of the meters you mentioned are reported or executed (added to the raw meter data).

Further analysis of the other equations reveals the right amount of losses were properly determined. The electrical equations are correct and truly reflected the power flow of the system. It is only in the last process where all determined losses are to be added or subtracted from the raw meter data which some of the equations unintentionally got wrong. Also, the losses of the other 9 metering points in that MTN were not affected since their last equation remained “raw meter data + line losses”.

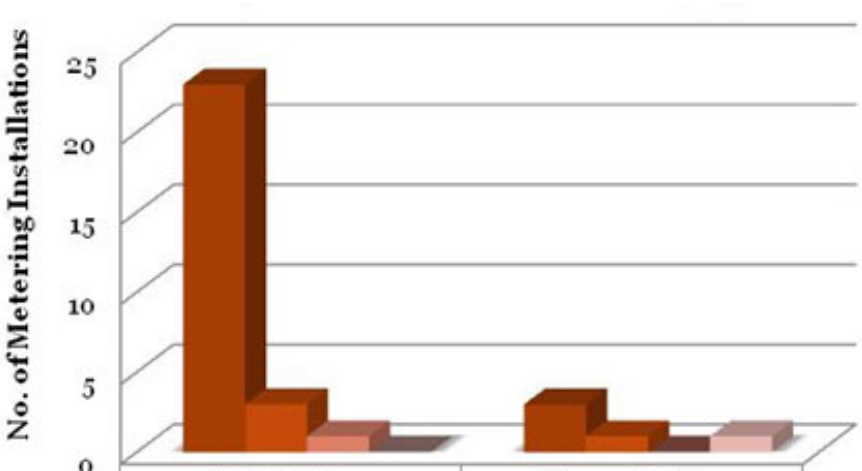
Functional Display (MI – PI03)

WESM-MSDM-007 Metering Standards and Procedures, Section 4.5.1 (c) Metering Installation Components:

A metering installation shall contain a device which has a visible or an equivalently accessible display of metering data or which allows the metering data to be accessed and read at the same time by portable computer or other equipment of a type or specification reasonably acceptable to all entities who are entitled to have access to that metering data.

Observation

Figure 12: Inadequate or Non-functional Display



	Main Meter	Alternate Meter
Burnt-Out	23	3
Partially Blurred	3	1
Flickering	1	0
Error Display	0	1

During the physical site inspection, it was discovered that **27 out of 216 (12.50%)** main meter installations and **5 out of 216 (2.31%)** of the alternate meters have non-functional displays (burnt-out, blurred, or flickering). Also, for main revenue meters, the brand that encounters the display functionality issues is EIG Nexus 1272. It may be inferred that the existence of non-functional display in meters is caused by the performance of the meter, an inadequate preventive maintenance as well as the environmental conditions of the metering facilities.

Risk Implication

An accessible meter display is essential for the following reasons:

a. It is a standard requirement as a metering installation component by the WESM Rules;
b. It provides ease to access readily available data without having a portable computer or other equipment of a type or specification connected to it;
c. It is, if not entirely, at least a standard and on-the-spot manifestation that the metering installation is functioning, uncompromised, and the details provided by the display are consistent with what are

shown in the portable computer, or any equipment of a type, attached into the meter, with the MV-90, and with other related information, if any.

While the absence or reduced clarity of the meter display does not conclude that the metering process is compromised, the condition may raise uncertainty on the integrity of the meter data.

Current Practice

Revenue meters with electronic registers use digital displays to indicate power readings and other information. The digital displays show a series of readings, automatically stepping through each parameter at a programmed rate.

One of the general causes of the blurred or burnt-out meter display is the extremely high temperature. This happens when the actual temperature exceeds the maximum temperature tolerable by the meter, over a particular period of time.

Recommended Practice

Additional maintenance activities should be considered with regard to the physical inspection of the metering installation:

a. Implement a Meter Performance Monitoring Program- the program is based on the application of statistical sampling of the meter population to identify the performance of the functional displays of various meter types in current service. It should establish and document methodologies for:

- Implementation
- Determination of categories, population and samples
- Sampling plan
- Metrology
- Analysis of Results
- Reporting
- Corrective Actions

b. Maintain a closer coordination or contact with the trading participants and establish protocols on how to properly communicate and resolve the issues regarding the condition of the metering installation. Courses of action may be as follows:

- Incorporate adequate viewing windows on the meter enclosures;
- Maintain personnel dedicated to periodically oversee the condition of the metering installation;
- Establish a 24/7 hotline to communicate the issues regarding the condition of the metering installation;
- Establish standard procedures on how to properly and timely resolve the issues; and
- Document and monitor the condition and performance of the metering installations.

Management Comments

The meter display fades due to usage and age and not because of extremely high temperature. Also, since the observation is related to a particular brand of meter, this cannot be addressed by preventive maintenance alone.

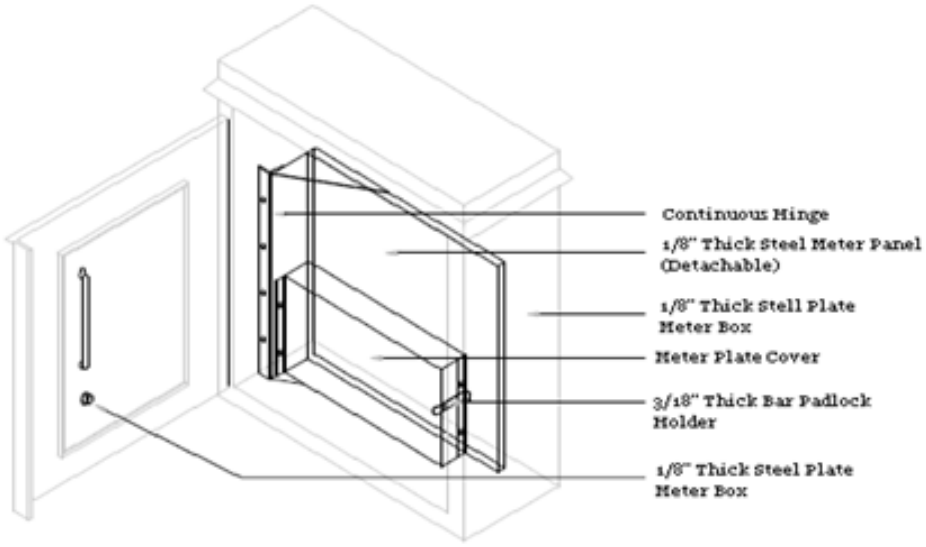
Note that all Nexus batch observed to have non-functional displays are currently being replaced as of date.

Cabinet Housing (MI – PI05)

WESM-MSDM-MM-007 Metering Standards and Procedures, Section 2.4.1 – Requirements for Grid Revenue Meters, the Meter Enclosure shall be provided with the necessary cover to protect the internal component against the harmful elements of environment that may affect its measuring circuit and operation.

Also, WESM-MSDM-MM-007, Section 2.9.1.4 - Meter Enclosure specifies that all meters, test links, and communication equipment shall be contained within a meter enclosure similar to Figure 5 of the manual, as replicated below:

Figure 13: Meter Enclosure

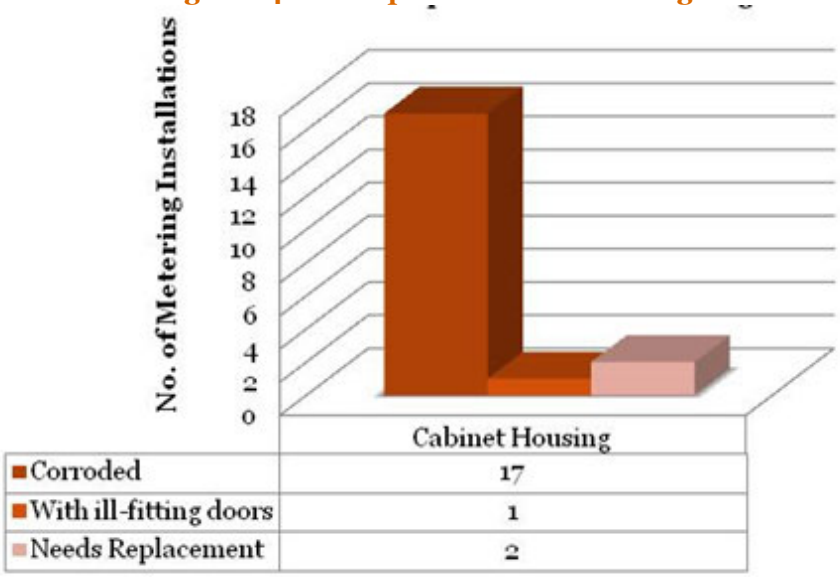


METER BOX ISOMETRIC VIEW

Accordingly, the meter enclosure shall be weatherproof (WESM-MSDM-MM-007 Metering Standards and Procedures, Section 2.4.1 – Requirements for Grid Revenue Meters Section 2.9.1.4.(a)(v)) and is capable to protect its internal components from the ingress of animal or infestation, water, humidity and other contaminants. The material and finish shall be of a class that best suits to the location of the metering facility and its environment.

Observation

Figure 14: Inadequate Cabinet Housing



It was discovered that **20 out of 216** meter enclosures are inadequate (**17 out of 216 (7.87%)** meter installations are corroded, rusted or needs repainting, **1 out of 216 (0.46%)** has ill-fitting doors and **2 out of 216 (0.93%)** need immediate replacement.). Furthermore, the ingress of animals such as lizards and water, were also observed to exist in some meter enclosures. These observations are not in conformance with the provisions of WESM-MSDM-MM-007 Metering Standards and Procedures, Section 2.4.1 – Requirements for Grid Revenue Meters.

Risk Implication

The likelihood of corrosion of the meter enclosures upon exposure to harmful elements of the environment may affect its measuring circuit and the operations of the enclosed equipments such as revenue meters, modem, cables and wires, etc.

The ingress of animals, vermin, water, excessive humidity and other contaminants into the enclosure may lead to possible shorting of terminals on the test blocks, cut or damaged wires and communication cables and other instances that may affect the performance and function of the enclosed equipments.

Recommended Practice

Meter enclosures which are subject to corrosion under normal working conditions should be protected more effectively. A consideration should be made on the environmental condition of the metering facility in the application of preventive maintenance on the meter enclosure and the enclosed equipments (e.g. more frequent inspection and maintenance for the sites that are located nearby the sea and power-generating facilities, etc.).

The structure of the meter enclosure should be made of an adequate material that will mitigate or prevent the harmful elements of the environment from affecting the measuring circuit and operation. Accordingly, the enclosure should conform to Index of Protection (IP) Ratings, an international standard that classifies and rates the degree of protection provided against the intrusion of solid objects or materials, and liquids like water in mechanical casings and electrical enclosures; and be suitably designed for satisfactory operation under the hot and hazardous tropical climate conditions.

In selecting the most proper enclosure material for a particular metering facility the following factors should be considered:

a. The location of the facility and its environment;
b. The size of the meters and other equipments installed;
c. The likelihood of animal and vermin ingress or infestation;
d. The likelihood of ingress of water and excessive humidity;
e. The likelihood of ingress of contaminants such as dust, copper, metal particles and other elements present on the metering site.

Management Comments

The meter installations that need replacement are already scheduled to be replaced. However, replacement of meter cabinet would require deenergization of sub-stations, thus needs planning and time.

Enclosure Security (MI - PI08)

Philippine Grid Code, Section 8.4.5.2 – Metering Equipment Security provides that the Metering Services Provider shall take all reasonable steps to prevent unauthorized interference with the equipment.

WESM-MSDM-007 Metering Standards and Procedures, Section 2.9.1.4 (a) Meter Enclosure Requirements states that the meter enclosure shall comply with the following requirements:

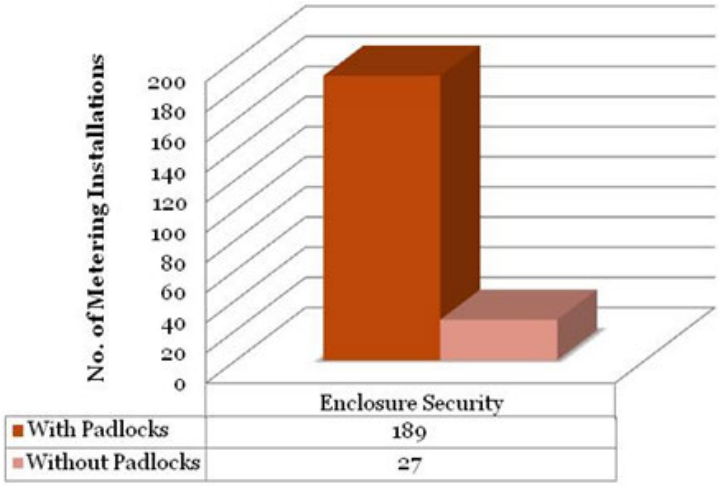
i. The meter enclosure shall be secured by the meter service provider.
ii. The meter service provider shall have access to the meter enclosure at all times.
iii. Persons other than the meter service provider shall not be given access to the meter enclosure.
iv. The meter enclosure shall be padlocked and sealed as far as practicable in a manner approved by the MO.

Also, WESM-MSDM-007 Metering Standards and Procedures, Section 2.9.1.6 - Meter Seals and Padlock provides for the following padlock requirements:

i. Padlock shall be heavy duty
ii. Padlock shall have only one security key and placed on a secured area
iii. Security key shall be controlled by MSP
iv. Use of security key shall be documented and monitored

Observation

Figure 15: Inadequate Enclosure Security



It was observed during the physical site inspection that **27 out of 216 (12.50%)** sites did not use padlocks as a security measure for the meter enclosure. Moreover, some meter enclosures did not have provisions (hasp) for the installation of padlocks while others were designed using keyed (or cabinet) locks that are loose and easy to be picked.

Improper custody on the security keys was also observed in South Luzon South Sector.

Risk Implication

The inadequacy of the enclosure security exposes the risk of unauthorized access to, destruction of and possible alterations to the metering installations.

Recommended Practice

To properly attend to the security measures on the metering installation, the use of padlock should be strictly implemented. While there may be some cabinet locks that provide almost the same level of security, the use of padlocks is highly recommended. Along the security that its body and shackle provide, a padlock generally offers a higher level of security than a cabinet lock in terms of the internal locking mechanism.

The American Society for Testing and Materials (ASTM) Designation F 883-04 - *Standard Performance Specification for Padlocks* provides for specifications covering environmental, functional, operational, and security requirements for padlocks. This standard may be considered in the procurement of the most suitable brand of padlocks to be used for the meter enclosures.

Furthermore, an enhancement of the controls on how to properly secure the keys should be implemented and monitored. The following procedures should be considered:

a. Establishment of a secured area dedicated for the safekeeping of security keys. Take note that there shall only be one (1) key for each meter enclosure padlock;
b. Assignment of responsibility over the safekeeping of the security keys to a dedicated personnel;
c. Establishment of operating procedures with regard to the proper usage of keys including, but not limited to the following:

- proper approval process on the use of security keys;
- any reason for use;

- documentation and monitoring such as logbook of the access to the security keys;
- the maximum number of hours allowed to use and return the security keys;
- penalties in case of loss; and
- procedures for replacement

Management Comments

We noted the recommendation but we want to emphasize that padlock and enclosure lock provide the same level of security.

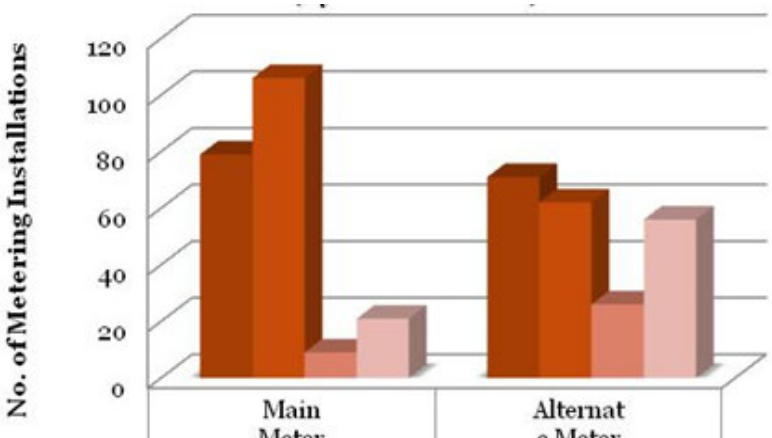
Meter Time vs. System Time (MI – PI04)

WESM Rules, Section 4.5.8.1 - Meter Time specifies that the Metering Services Provider shall ensure that all Metering Installation and data logger clocks are referenced to Philippines Standard Time (PST).

WESM-MSDM-MM-007 Metering Standards and Procedures, Section 2.4.1 – Requirements for Grid Revenue Meters states that the meter shall have an internal clock with an allowable error of +/-1 second per demand interval.

Observation

Figure 16: Time Differences (System Time vs. Meter Time)



	Main Meter	Alternate Meter
Five (5) minutes or less	79	71
Zero (0)	106	62
More than five (5) minutes	9	26
Not applicable	21	56

Note that de-energized meters, metering points having no alternate meters and meters with burnt-out functional displays, were classified as "Not applicable" in the graph.

It was noted during the physical site inspection that out of 215 metering installations, **79** or **36.57%** have time discrepancies of less than five (5) minutes in the main meter while **9** or **4.17%** metering points were noted to have time discrepancies of more than five (5) minutes.

For the alternate meters, **71** or **32.87%** metering points were noted to have time discrepancies of less than five (5) minutes and **26** or **12.04%** metering points were noted to have time discrepancies of more than five (5) minutes.

Also, there are revenue meters (main and alternate) that have time discrepancies of more than five (5) minutes. Among the exceptions with large time differences are the following:

e. MNORTRAN02 (Main Meter) - 7 hours and 54 minutes
f. QTUVECO13 (Alternate Meter) - More than one 1 year
g. MNORTRAN01 (Alternate Meter) – 20 days, 4 hours and 46 minutes
h. MBTNBTNG02 (Alternate Meter) - 5 hours and 51 minutes

The factors that affect asynchronous time include various factors like the type of communication link used by the metering site (e.g. the signal strength propagation for the facilities that use GSM) and power interruptions or de-energization of the metering point for the conduct of preventive maintenance activities and other matters relating to the installation or replacement of equipments.

Risk Implication

There is a likelihood of retrieving inaccurate meter data in view of the fact that it does not reflect the measured energy at an exact particular time. Since the meter installations capture the meter data cumulatively, these time discrepancies may result to recurring and successive errors until detected.

Current Practice

The metering database system (MV-90) has the functionality to automatically synchronize the system and meter time differences of up to +/- five (5) minutes so that when the retrieval of energy consumption (and dispatch) happens, an accurate meter reading is produced.

For the metering installations with delayed or advanced time in excess of the allowable error, the MSP resets the clock manually over a certain standard procedure and upon securing proper approval from the MSD.

Recommended Practice

Since the time-synchronization functionality already exists in the metering database system, periodic monitoring and performance measurement program on time synchronization is recommended. The following procedures should be incorporated into the program:

a. Establishment of a hotline to specifically handle the periodic (i.e. weekly or monthly) reporting of the Trading Participants on the accuracy of the meter time and the discrepancies noted against the MV-90 records;

b. Creation of exception reports and investigation on the possible cause(s) of the time discrepancies that go beyond 5 minutes, if any, and other relevant issues;

c. Addressing the exceptions and other issues noted within a reasonable turnaround time (e.g. within 24 hours to reset the meters where discrepancies of more than 5 minutes were noted) to at least minimise, if not eliminate, the risk associated with these circumstances;
d. Periodic review and reporting on the performance of the meters in relation to the behaviour of their time functionalities, including any explanation for such behaviour;

e. Establishment of other related protocols or procedures that could further address the issues noted and to operate the program more efficiently and effectively.

Management Comments

The power of the meters is connected to the PTs and when the site is deenergized, the meter will also shut-down. This is one of the reasons why there are large meter time discrepancies. MSP believes that signal strength has no direct impact on this observation.

MSP does not agree with the level of non-compliance since discrepancies are mainly caused by deenergization of the substation rather than negligence on time synchronization.

Section 4: Non-compliances to Documented Internal Business Procedures

Work Instruction Manual (PEMC – ITGC01)

ISMS Policy Matrix (PEMC-ISM-2011.003) Control No. 10.1.1 Documented Operating states that Internal Business Processes of PEMC shall be determined, documented, maintained, reviewed and made available to all employees.

All PEMC departments must ensure that their respective internal business processes and operating procedures that are associated with information processing are updated / revised for alignment with ISO standards in Information Security, depending on the company's chosen ISO controls. For operating procedures that have not yet been documented, documentation must be completed, specifically for those which might be prone to the risks identified during risk assessment.

Observation

Work Instruction Manual provided by BSMD does not include information processing controls. In addition, it is not documented so as to be aligned with the ISO standard implemented for PEMC. At a minimum, the Procedure Manual should include the following:

e. Access Matrix
f. User Access Registration and Review procedure
g. Backup procedures (since almost all processes includes the use of macro-based programs and spreadsheets)
h. Periodic Review of the results of processes

This is with the understanding that POMAX, MV90, macro-based programs and spreadsheets used by BSMD is not maintained and/or monitored by the central IST.

Risk Implication

If operating procedures are not completely documented, there is an increased risk that information processing facilities may not be operated correctly and in accordance with the set security policy.

Recommended Practice

As best practice, the operating procedures of Metering Department should specify the instructions for the detailed execution of each job including:

a. backup
b. scheduling requirements, including interdependencies with other systems, earliest job start and latest job completion times
c. instructions for handling errors or other exceptional conditions, which might arise during job execution, including restrictions on the use of system utilities
d. support contacts in the event of unexpected operational or technical difficulties
e. special output and media handling instructions, such as the use of special stationery or the management of confidential output including procedures for secure disposal of output from failed jobs
f. system restart and recovery procedures for use in the event of system failure
g. audit-trail and system log management

Operating procedures, and the documented procedures for system activities, should be treated as formal documents and changes should be authorized and formalized.

Management Comments

The MO did not make any comments either documented or during the discussion. As such, we deemed that the auditee accepted the observation and will consider the recommendations.

User Access Management (PEMC – ITGC02)

ISMS Policy Matrix (PEMC-ISM-2011.003) Control No. 11.2 states that formal procedures and guidelines shall be established, implemented and monitored to manage user access including registration and de-registration, allocation and use of privileges, allocation of passwords and review / approval of user's access rights at regular intervals.

Logical Access Management Policy (PEMC-POL-2011-005) 3.5 Access Account Administration and Monitoring also states that to systematically monitor and enforce compliance to the policies in this section and at the same time ensure that proper security and confidentiality is observed among the departments of the corporation, a centralized logical access account administration and monitoring with decentralized review and approval shall be followed. Under this setup, responsibilities shall be delegated down to individual accounts for empowerment and security with bottom-up reporting/review for check and balance and transparency.

Department Administrator shall be responsible for review and approval of access accounts request for ICT systems and module/sections used largely by his department.

Individual users shall be responsible for ensuring the security and confidentiality of the access accounts assigned to him/her.

Observation

a. Maintenance of the POMAX and MV90 is not under the IT Department. As a result the access rights are not requested through the said department and are maintained by the Metering Department.

b. Metering Department, however, does not follow any formal procedure on creating and updating access rights in the aforementioned systems.

c. Metering Department uses only one (1) user ID for accessing POMAX (Username: HANDEL) which is shared by all the Metering Senior Specialist.

d. There are three (3) access rights created in MV90 with the following status:

- CRSCALUB: assigned to a MSS with administration and super user access rights. This ID has a system administration rights and can access all the functionality of the system.
- JLVPAZ: assigned to a MSS with administration and super user access rights.
- RBAFURONG: assigned to the Metering Assistant Manager with view and edit access rights to the system data and master files.

e. No defined access matrix is present for both MV90 and POMAX.

Risk Implication

Proper user access management could help prevent unauthorized access to information systems.
User access management allows an organization to track users' rights, and remove them in a timely manner when if necessary.

As a result the following are potentially compromised:

a. Accountability of the transaction processing in the system is compromised when all the end users share only one User ID.
b. Unauthorized changes to the following items can be made when an end user who process transactions is assigned a super user and administration access to the system.

- System Data (i.e. Raw and adjusted Meter Quantities)
- System Configuration
- Access and Security Configuration

System security may be compromised due to the absence of a guideline that should be followed in granting access audit and maintenance of proper segregation of duties.

Current Practice

As per inspection of the Metering Manual, there were no provisions / procedures in relation to access rights administration. There are no Access Security Documents for POMAX and MV90 that mandates a formal user registration and de-registration procedure for granting and revoking of access.

However, a Logical Access Management Procedure is documented by IST Department (ISTD) for all the application that is maintained and administered by ISTD. A Logical Access Management Form is used by ISTD to request for creation or update of user access rights for the systems they maintain.

Access Security Documents were not provided / maintained by the Metering Department since access to POMAX and MV90 are created by the implementers / vendor / developer during the time of implementation. The same access is carried over to the production phase and has never been changed ever since.

A screen shot of the last log-in and last update date from MV90 shows that the three (3) User IDs used for MV90 are last updated on the following dates:

a. RBAFURONG
Last Login Time: June 13, 2006
Password Modified: February 22, 2005

b. JLVPAZ
Last Login Time: May 20, 2010
Password Modified: February 22, 2005

c. CRSCALUB
Last Login Time: August 29, 2012
Password Modified: April 21, 2005

Further, a screenshot of the User ID from POMAX shows a creation date of November 18, 2007.

Also, there is no access matrix available for POMAX and MV90. However, since PEMC had scrapped the upgrade to MV90 xi, BSMD uses the MV90 as a redundant metering database next to POMAX, which is the official database of PEMC. Moreover, the MV90 software function would not run properly since there are problems due to obsolete patches that may create error in its output. As such, the Metering Unit decided to limit the use of the functionality of MV90 and to use it as additional tool to validate the accuracy and the correctness of the meter data. Hence new user access right to the MV90 software is no longer necessary.

As for POMAX, since July 2009, the system fails to calculate system validations as previously configured. With this, POMAX is only used as a repository and monitoring tool for the meter data. All the required validations are performed outside the system through the use of macro based programs. Hence creation of additional access rights in POMAX is also not critical.

Recommended Practice

As best practice, the access control procedure for user registration and de-registration should include:

a. using unique user IDs to enable users to be linked to and held responsible for their actions; the use of group IDs should only be permitted where they are necessary for business or operational reasons, and should be approved and documented
b. checking that the user has authorization from the system owner for the use of the information system or service; separate approval for access rights from management may also be implemented.
c. checking that the level of access granted is suitable to the business purpose and is consistent with organizational security policy, e.g. it does not compromise segregation of duties
d. giving users a written statement of their access rights
e. requiring users to sign statements indicating that they understand the conditions of access
f. ensuring service providers do not provide access until authorization procedures have been completed
g. maintaining a formal record of all persons registered to use the service
h. immediately removing or blocking access rights of users who have changed roles or jobs or left the organization
i. periodically checking for, and removing or blocking, redundant user IDs and accounts while ensuring that redundant user IDs are not issued to other users

Multi-user systems that require protection against unauthorized access should have the allocation of privileges controlled through a formal authorization process. The following steps should be taken:

a. the access privileges associated with each system product, e.g. operating system, database management system and each application, and the users to which they need to be allocated should be identified

b. privileges should be allocated to users on a need-to-use basis and on an event-by-event basis in line with the access control policy, i.e. the minimum requirement for their functional role only when needed

c. an authorization process and a record of all privileges allocated should be maintained and privileges should not be granted until the authorization process is complete

d. the development and use of system routines should be promoted to avoid the need to grant privileges to users

e. the development and use of programs which avoid the need to run with privileges should be promoted

f. special privileges should be assigned to a different user ID apart from those used for normal business use

Management Comments

The Metering group has already requested ISTD for the assignment of individual usernames and passwords for POMAX.

The use of MV-90 is limited; it only functions as a secondary metering database. The system is not updated. Additional usernames and passwords for the other Metering group personnel are not necessary since its functions are limited.

An internal memo was released for all departments to turn over all system administration under their possession.

In the interim, IT shall also study its systems administration features. Thereafter, if system is capable then individual usernames and passwords shall be created. Otherwise, IST shall maintain the existing three accounts on the on the Logical Access Exception List (IST-REP-2012-004 page 2) and shall be closely monitored by IOMD.

Please note that BSM has already filed a Logical Access Request for the additional usernames/passwords as recommended by the auditor.

Note: HANDEL is a default account in POMAX and if changed, will affect the operation of the application

POMAX and MV90 are included in our Logical Access Exception List. This is because of the application's obsolescence and limitation that we are unable to apply high security features. Based on our Logical Access Management, these types of systems/applications will be monitored closely.

Use of User ID (PEMC – ITGC03)

Logical Access Management Policy (PEMC-POL-2011-005) 3.5 Access Account Administration and Monitoring also states that to systematically monitor and enforce compliance to the policies in this section and at the same time ensure that proper security and confidentiality is observed among the departments of the corporation, a centralized logical access account administration and monitoring with decentralized review and approval shall be followed. Under this setup, responsibilities shall be delegated down to individual accounts for empowerment and security with bottom-up reporting/review for check and balance and transparency.

Department Administrator shall be responsible for review and approval of access accounts request for ICT systems and module/sections used largely by his department.

Individual users shall be responsible for ensuring the security and confidentiality of the access accounts assigned to him/her.

Observation

The User ID used by IT for resolution of errors / trouble shooting encountered using POMAX (ex. Errors regarding system configuration or system data processing) is the same User ID (username: HANDEL) used by the rest of the MSS for data processing.

Risk Implication

Persons doing technical assistance (troubleshooting) may accidentally / intentionally alter system data such as meter information thereby compromising its accuracy and integrity.

Also, not having proper segregation of duties increases the risk of accidental or deliberate system misuse such as unauthorized modification or alteration of information or services.

Current Practice

IT Department is not responsible for the administration of the various systems used by Metering Department. Whenever errors need to be resolved by IT Department, the requests for technical assistance is logged in WIMPSYS (the incident monitoring application of PEMC).

Recommended Practice

Segregation of duties is a method for reducing the risk of accidental or deliberate system misuse. Care should be taken that no single person can access, modify or use assets without authorization. The initiation of an event should be separated from its authorization.

Controls such as monitoring of activities, audit trails and management supervision should be considered and that audit of security should always be done independently by qualified departments / personnel.

Management Comments

Username and password for user of system configuration troubleshooting in POMAX and MV90 should be created by PEMC-ISTD.

This depends on the result of the study for PEMC-ITGC02, if feasible access matrix (Detailed Logical Access Control List) shall be created for both MV90 and POMAX.

Note: MV90 and POMAX are not exempted from the Logical Access Policy; please refer to Logical Access Management Procedure on how we handle systems with limitations such as this. Auditor may also refer to the Logical Exception List report IST wherein logical accesses of the said systems are being monitored by the Systems/database administrator.

Formal User Access Review Process (PEMC – ITGC04)

Logical Access Management Policy (PEMC-POL-2011-005) 3.5 Access Account Administration and Monitoring also states that Department Administrator shall be responsible for review and approval of access accounts request for ICT systems and module/sections used largely by his department.

Observation

There is no formal documentation of the review of the access rights for MV90 and POMAX.

Risk Implication

The lack of a formal user access review process increases the risk that users retain or obtain unauthorized levels of access to systems or data.

Recommended Practice

As best practice, the review of access rights should consider the following guidelines:

a. users' access rights should be reviewed at regular intervals, e.g. a period of 6 months, and after any changes, such as promotion, demotion, or termination of employment
b. user access rights should be reviewed and re-allocated when moving from one employment to another within the same organization
c. authorizations for special privileged access rights should be reviewed at more frequent intervals, e.g. at a period of 3 months
d. privilege allocations should be checked at regular intervals to ensure that unauthorized privileges have not been obtained
e. changes to privileged accounts should be logged for periodic review

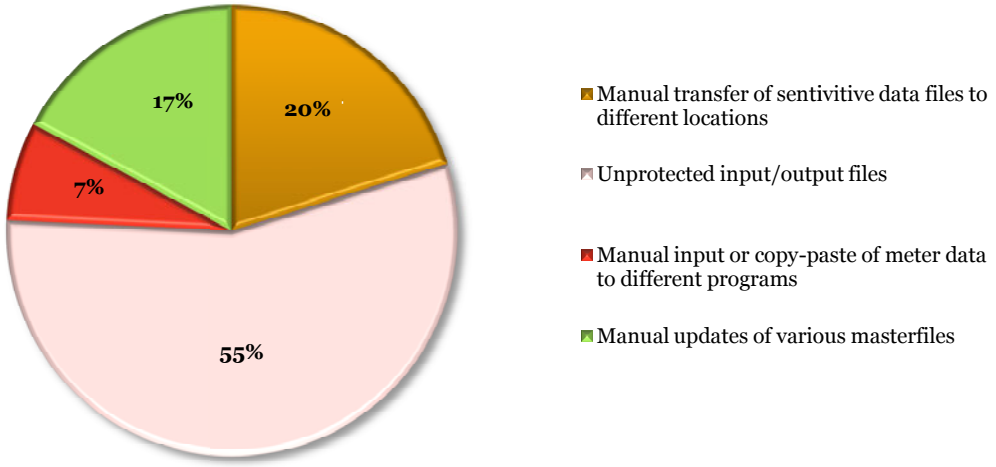
Management Comments

As per formal response sent by the MO on November 29, 2012, their management comment for this observation is the same as the comments made for the observation regarding the use of User ID (PEMC-ITGC003).

Section 5: Significant Observations Requiring Immediate Corrective Action

Manual Business Process Implemented in BSMD (PEMC – VEE01)

Figure 17: Control Gaps from Various Processes



The review team noted four (4) control gaps that were constantly present in various processes of BSMD. These control gaps occurred sixty-two (62) times through-out the Validation, Estimation and Editing (VEE) and SSLA Processes.

Fifty-five percent (55%) of the controls gaps noted were occurrences related to unprotected data files used as an input to a process or as an output of certain programs used. This was composed of thirty-two (32) different data files that contain sensitive information which may affect the outcome of the settlement values. Most of the input files used and/or output files generated in various processes of BSMD were editable and not protected giving opportunity for unauthorized / accidental data changes.

Twenty percent (20%) or fourteen (14) counts of the control gaps noted were occurrences of manual copy-paste activities of various data files used for the VEE and SSLA processing. This component of the process is susceptible to human error.

BSMD uses fourteen (14) macro-based programs, four (4) scripts and two (2) templates through-out the metering processes. Eleven (11) out of these twenty (20) files have master files that are manually updated by the Metering Senior Specialist. These compose seventeen percent (17%) of the control gaps noted. With this, master file maintenance may not be properly implemented thus resulting to unsynchronized master data in different locations.

Five (5) out of the twenty (20) files used for processing meter data requires the Metering Senior Specialist (MSS) to manually input and/or copy-paste meter information inside the program/script/template. This is seven percent (7%) of the control gaps noted. The inclusion of human intervention in the process poses higher risk on data integrity than that of an automated one. Please refer *to Appendix 12: Validation, Estimation and Editing Process Flow*

Other controls gaps noted are the following:

Table 7: Other Control Gaps noted in PEMC's business process

Process	IPO	Detail
Daily MDEF Monitoring and MTR Issuance	Validity	There are no controls to check if the results of the MDEF Monitoring, specifically those with "NO MDEF" status are validly captured in the MTR Summary Report.
Daily SSLA Calculation	Accuracy	There are no controls that checks whether the program accurately made the conversion from the 15-minute reading into an hourly data. These files are used as an input for the SSLA Calculation.
Monthly Validating Average RTU	Validity	The actual dispatch files from TOPD will be used regardless if differences are still present to the new files provided.
Monthly Validating Average RTU	Validity	The results of the RTU Status Summary Report are not considered in averaging the 15-minute RTU snap shots.
Monthly Updating the Masterfile	Accuracy	The use of RTU data to stipulate the changes that needs to be made in the SSLA model pose risk that the changes are not an accurate representation of the actual physical metering models in the sites
Monthly Metering Validation	Accuracy	If the SEINs are noted to be invalid, the filename is changed, if needed, using a command from the macro-based program. The contents of the file, however, are manually changed to reflect the new SEIN.

The review team believe that various control gaps noted through-out the metering processes were greatly caused by the highly manual business process implemented in BSMD coupled with non-standard programs/applications used for meter data validation and SSLA computation.

We observed that the macro-based programs used by BSMD did not go through any formal implementation procedure as prescribed by the ISMS policies of PEMC. The programs are also created / developed by one of the Metering Senior Specialist MSS instead of by the IT Department.

Sensitive information and data files were also stored in different locations which were deemed ineffective in versions and changes monitoring.

Risk Implication

Highly manual processes are prone to human error posing risk to data integrity. Also, if applications do not go through any formal implementation procedure, there are high risks that business requirements are not properly met and that critical information may be processed inappropriately.

Recommended Practice

BSMD is recommended to automate the metering process and consider upgrading MV90 and/or POMAX so as to utilize its functionalities. Developing an in-house application for metering procedures may also be considered, however, development and implementation stages should carefully be planned to ensure that business requirements are met and proper risk assessment is made.

As an interim procedure, BSMD is recommended to have a central repository to store the (a) master file and (b) inputs/outputs of the macro-based programs. This procedure will eliminate the manual copy-paste component when running the program to avoid the risk of unintentional changes on the data.

The manual transfer of data files may also be eliminated by implementation of an automated control to transfer files from one folder to a destination folder (i.e., central repository). There are available applications that may be used to manage, schedule and automate file transfers based on the name, modification date, size or file type of data. These applications have the capacity to continue transfers that have been interrupted. Some of the applications may also have the capacity to record all the actions performed on File Transfer Protocol (FTP) server and keeps detailed logs showing all actions that can be saved either locally or to an FTP server, or have them emailed to any address.

Master files in various programs should also be updated automatically based on the updates made by one person assigned to maintain the central data repository of the meter installation. This is possible if all macro-based programs will look-up to a central master data file which contains all the details needed in metering processes.

Management Comments

To implement this recommendation, BSMD should undergo a change management process. There is a pending project called Central Registration and Settlement System (CRSS) in which the automation of various manual processes will be covered.

Manual Elements in the Issuance of the Monthly Metering Validation Report (PEMC – VEE08)

Currently, there are four (4) Generator Market Nodes with the following Site Equipment ID which are deemed as special cases:

a. MF3MANGAHEP01
b. MF3MANGAHEP02
c. MF3MANGAHEP03
d. MF3MBACBACM01
e. MF3MBACBACM02
f. MF3MMASMASI01
g. MF3MMASMASI02
h. MF3MKSPKSPC01
i. MF3MLB1LBG101
j. MF3MKSPKSPC02

These cases have multiple MTNs sharing one metering installation. In the process of issuing a Monthly Metering Validation Report, these cases are always automatically flagged as discrepancy in the SSLA Raw vs. CD Validation Report and WESM-MET MF Validation Report.

To effectively carry out the VEE process, the process owner needs to be aware of which meter installations are included in the special cases so he can manually remove the flags raised in the monthly metering validation and summary report.

Risk Implication

If the process owner mistakenly removes the discrepancy flags from the report, invalid data may pass through the VEE process.

Recommended Practice

a. Integrate the special cases into the programs that can automatically handle these situations throughout the VEE process by allocating the meter quantities based on RTU measurement.

b. In the process of issuance of the monthly metering validation report, use the allocated meter quantities as a reference to check the validity of the metering procedure

Management Comments

The special cases or all the SEINs indicated are Generator meters and BSMD/Metering does not apply SSLA for generator meters as this will only increase the registered meter data including the station service consumption of the generator. Metering has already integrated the special cases into the macro program.

Reconciled Site Specific Loss Adjustment (SSLA) vs. SSLA Models (PEMC – SSLA01)

The review team have observed instances of days where changes in shifting configuration occurred while the reconciled results did not reflect a sequence of SSLA models consistent with the sequence of shifting configurations. *Please see Appendix 5: SSLA Calculation vs. SSLA Models for the details of the inconsistencies noted by the review team.*

Thus, there have been instances where the adjustment methodology referred to in clause 3.2.2.3 of the WESM Rules was not correctly implemented by the Market Operator.

Risk Implication

There is a non-negligible risk that the irregularities observed may be present in the SSLA data that were used to settle participant accounts.

Also, even if observed irregularities are only present in preliminary SSLA data (and not in SSLA data used in settlement), the review team is of the opinion that they are a strong indication that the reconciliation process in place is not as robust as it should be. There is no guarantee that this process will not lead to irregularities in SSLA results used to settle participant accounts.

Audit Limitation

The review team's observations pertain to preliminary adjustments and/or SSLA data provided which, in our opinion, might not be used to settle participants' accounts. However, we were not able (i.e. we were not provided with the right data) to check if similar irregularities were present in final SSLA data (which are used in settlement).

If this is the case, then there have been instances where the SSLA models used to adjust meter quantities for settlement were not accurately representing the shifting configurations of the system.

If, on the other hand, all the observations presented were identified by BSMD and corrected before the SSLA data was actually used to settle participant accounts, then we are of the opinion that these observations do not constitute a breach of the WESM Rules.

Current Practice

To account for the shifting of metering points between MTN that happens intermittently during a billing period, the SSLA procedures use separate SSLA models. Each model represents a particular shifting configuration.

The SSLA procedure calculates the loss adjustments for an entire day at a time. On days where the shifting configuration changes daily adjustments are calculated several times.

Adjustments generated with the different SSLA models are then manually reconciled to produce final results that account for the actual succession of shifting configurations in each day.

To illustrate this, consider the following fictive example.

Assume that on a given day, the shifting configuration changes twice as follows:

Hour 9: change from shifting configuration A to shifting configuration B, and
Hour 16: change back to shifting configuration A.

Assume now that SSLA models A and B were developed to represent shifting configurations A and B respectively. To generate the loss adjustments for that particular day, the SSLA procedure needs to be run twice: once with SSLA model A and once with SSLA model B. Then the results thus generated need to be manually reconciled to account for the following sequence of SSLA models:

Results from model A apply from hour 1 to hour 8, then
Results from model B apply from hour 9 to hour 15, then
Results from model A apply again from hour 16 to hour 24.

This procedure is in line with *WESM 3.2.2 Market Trading Node which specifically states that if the connection point of the Trading Participant could not be represented in the market model or if a particular market trading node must be assigned to more than one Trading Participant because the conditions set in clause 3.2.2.2 are not met, the affected Trading Participants, the Metering Service Provider and the Network Service provider will mutually agree on adjustments that will be implemented by the Market Operator and the System Operator.*

Recommended Practice

The reconciliation process that is currently in place has a high manual components. The observed irregularities may have resulted from errors introduced during this manual process. This finding supports a general recommendation that consideration should be given to the development of a more robust, SSLA processing engine that does not rely on the maintenance and management of multiple spreadsheets.

Management Comments

BSMD has reviewed the findings in detail and acknowledges that there have been some irregularities in the file sequencing as observed. However, they make the following points:

a. Final switching configurations are not available until near the time of final monthly reconciliation for settlement. Until then, the last available SSLA model is used for daily and preliminary SSLA runs. The audit team understands this limitation, but we note that the initial runs will always have this caveat attached to them and are less useful for review as a result. This finding supports a recommendation to obtain timely switching information from network owners, as well as improving the SSLA process. Also, this fact does not necessarily explain the irregularities observed.

b. BSMD asserts that all the irregularities observed above are corrected and signed off before settlement. As noted above, the audit team was not able to confirm this one way or the other. This observation is therefore classified as an opportunity for improvement, with the audit limitation noted above.

Unusually Large Line Losses in SSLA Data (PEMC – SSLA03)

WESM 3.2.2 Market Trading Node specifically states that if the connection point of the Trading Participant could not be represented in the market model or if a particular market trading node must be assigned to more than one Trading Participant because the conditions set in clause 3.2.2.2 are not met, the affected Trading Participants, the Metering Service Provider and the Network Service provider will mutually agree on adjustments that will be implemented by the Market Operator and the System Operator.

Observation

On November 20 2011, unusually large line losses (as compared to the raw meter readings) were observed in the SSLA results for meters MF3MCLNMECO01 and MF3MCLNMECO02. These line losses are so large that, at hour 6, the resulting loss adjustments turn positive raw quantities into negative adjusted quantities. *Please see Appendix 8: Large Line Losses in SSLA Data for the details of the observations noted.*

Risk Implication

When the switching configuration is such that the embedded customer's hosts are not the actual customers but a third party customer, and when PEMC's BSMD is not aware of this situation, the following may happen:

a. The embedded customer's load is correctly recorded as part of the host customer's raw load measurement.
b. The embedded customer's load is not removed from (i.e. is included in) the host customer's adjusted load and is therefore charged to the host customer.
c. The embedded customer's load is removed from customers MF3MCLNMECO01's and MF3MCLNMECO02's adjusted loads therefore reducing their amounts chargeable by that much.

The problem arises when PEMC is not aware of the changed switching configuration. In this situation the SSLF calculation does not reflect the changed power flows. This clearly constitutes a non-compliance with clause 3.2.2.3 of the WESM Rules.

Recommended Practice

We recommend the following steps be taken:

a. Develop and implement a procedure with the DU in charge of the embedded customer to inform PEMC's BSMD of any changes in the switching configuration.

b. Develop a new SSLA template compatible with the situation where MF3MCLNMECO01 and MF3MCLNMECO02 are not the embedded customer's hosts.

Management Comments

BSMD agrees with this recommendation. BSMD staff pointed out in this and other similar situations, they have no immediate control over what is done and BSMD does not have a single line diagram of the configuration. For this reason BSMD does not believe it should be classified a major non-compliance. However, the problem remains wherein the situation is non-compliant and should still be fixed. Therefore, we retain our original level of non-compliance classification.

As per official comments sent on November 29, 2012:

The line losses attributed to these meters are actually the consumptions of an embedded customer treated as negative line losses. The sum of these two host meters should always be greater than the embedded customer.

The MSP declared that all three meter readings are correct and valid. Since the sum of these two host meters being less than the embedded customer, this could mean the embedded customer sourced its power from another host meter. Regardless of what node and/or DU grid metering points (registered in the WESM) the embedded meter source it power, the energy is accounted considering the meter is within the DU franchise area.

The solution to this finding is for the DU to inform PEMC every time there will be a switching on the source power for this embedded meter. This is a special case treated by PEMC since this meter is located and/or within the franchise area of the DU. PEMC disagree to the Major non-compliance.

This is about the Sun-Power meters which are not registered in WESM inside the Meralco Compound (since 2007). Note that this is the only meter not registered in WESM.

The trading participant requested the data to be sent thru PEMC. (This is a special case involving a government subsidy price)

The issue is that the configuration of the system (e.g. line diagram) is not properly communicated to PEMC. PEMC does not know where the meters get its power.

PEMC agreed to the recommendation. This will be addressed in the implementation of RCOA.

The customer affected is in agreement of the computations/adjustments made by MO.

Large negative losses in SSLA data (MF3MITOBENE08) (PEMC – SSLA04)

WESM 3.2.2 Market Trading Node specifically states that if the connection point of the Trading Participant could not be represented in the market model or if a particular market trading node must be assigned to more than one Trading Participant because the conditions set in clause 3.2.2.2 are not met, the affected Trading Participants, the Metering Service Provider and the Network Service provider will mutually agree on adjustments that will be implemented by the Market Operator and the System Operator.

Observation

Large negative losses were observed in the SSLA results for meter MF3MITOBENE08. As a result of this, positive raw meter quantities were adjusted to negative quantities. *Please refer to Appendix 9: Large Negative Losses in SSLA Data for the details of the observation noted by the review team.*

Risk Implication

Every time embedded generator ITOHEDC04 is supplying power directly to embedded customer ITOPMCZ02, the following happens:

a. ITOPMCZ02's load is netted out of host customer MF3MITOBENE08's load during its loss adjustment computations.

b. However, the part of ITOPMCZ02's load supplied directly from embedded generator ITOHEDC04 is not reintegrated to customer MF3MITOBENE08's adjusted load.
c. Therefore an amount of consumption, equal to the amount of power ITOHEDC04 supplies directly to embedded customer ITOPMCZ02 is effectively removed from customer MF3MITOBENE08's adjusted load reducing the amount chargeable to this customer by the same amount.

This clearly constitutes a non-compliance with clause 3.2.2.3 of the WESM Rules.

Recommended Practice

Two alternative courses could be taken:

a. Request NGCP and the TP in charge of embedded load ITOPMCZ02 and embedded generator ITOHEDC04 to set up metering installations to provide PEMC's BSMD with accurate measurements of the amounts of power generated by ITOHEDC04 and directly supplied to ITOPMCZ02; or
b. Request NGCP and the TP in charge of host load MF3MITOBENE08 to set up a metering installation exclusively dedicated to load MF3MITOBENE08.

Whichever option is selected, PEMC's BSMD should also modify the corresponding SSLA model accordingly.

Management Comments

BSMD agrees with the finding and recommendation but noted the following:

a. The situation in this case does not affect other parties and there have been no complaints
b. BSMD does not have control of the specific arrangements in place.

For this reason BSMD does not believe it should be classified a major non-compliance. However, the problem remains wherein the situation is non-compliant and should still be fixed. Therefore, we retain our original level of non-compliance classification.

As per official comments sent on November 29, 2012:

TOBENE08: this meter is host to three other embedded customers, and one embedded generator, namely:

a. ITOPMCZ02
b. ITONIAA01, and
c. ITONPCZ01
d. ITOHEDC04 (generator)

From the set-up of this particular network, if the generator has no injection, then the host meter should be greater than the sum of the embedded customers. In the particular trading hour where the computed adjusted meter data for ITOBENE08 became negative, the raw meter data of ITOPMCZ02 is greater than the raw meter data of ITOBENE08, which means that part of the supply came from the embedded generator. In any situation for this MTN model, the adjusted meter data of ITOBENE08 should never be negative.

This is a special case since BENECO has no particular meters to directly register their consumption. PEMC had reminded the Trading Participant of ITOBENE08 (BENECO) and the MSP to install a meter dedicated for the load of BENECO to avoid very complex power flow mathematics in determining the adjusted meter data of the other Trading Participants. PEMC should not be accounted on this observation considering the trading participant should be responsible for none installation of several metering points.

Large Line Losses in SSLA Data (MF3MROSCEPZ03) (PEMC – SSLA05)

WESM 3.2.2 Market Trading Node specifically states that if the connection point of the Trading Participant could not be represented in the market model or if a particular market trading node must be assigned to more than one Trading Participant because the conditions set in clause 3.2.2.2 are not met, the affected Trading Participants, the Metering Service Provider and the Network Service provider will mutually agree on adjustments that will be implemented by the Market Operator and the System Operator.

Observation

Large negative line losses were observed in the SSLA results for meter MF3MROSCEPZ03. As a result of this, MF3MROSCEPZ03's positive raw measurement was turned into a negative quantity by the loss adjustment model. *Please see Appendix 10: Large Negative Line Losses in SSLA Data for the details of the observation noted by the review team.*

Risk Implication

At hour 16 on November 19, 2011, MF3MROSCEPZ03's raw measured load was loss adjusted using erroneous data supplied by one of MF3MROSCEPZ03's local supplier. As a result, the adjusted load for that period was negative.

This observation seems to indicate that there are no tests in place to detect errors or irregularities in data provided by local suppliers that is used in the SSLA process. Therefore any undetected irregularities result in erroneous loss adjustments and inaccurate settlement calculations.

Recommended Practice

We suggest that some kind of testing is implemented to check and validate data used in the SSLA computations that is provided by local suppliers. The tests could be performed before and after the SSLA process is carried out.

For instance, scrutinising the SSLA output data given in the above observation would have clearly revealed some kind of irregularity.

Management Comments

BSMD agrees with the findings and the recommendation.

As per official comments sent on November 29, 2012:

The meter ROSCEPZ03 has a virtually embedded meter ROSCEPZ05 due to CEPZA having multiple suppliers. The ROSCEPZ05 is the BCQ of one of the suppliers treated as meter data which is being deducted to the reading of ROSCEPZ03. The value of ROSCEPZ05 is determined by supplier. In those hours when the adjusted value of ROSCEPZ03 is negative due to the supplier submitting a value for ROSCEPZ05 greater than that of the ROSCEPZ03. PEMC disagree on the major non-compliance on this finding.

Please note that the adjusted data will be computed based on the data which is provided by MSP. If the data (BCQ - data to be deducted to the adjusted meter quantity; this is a virtual meter data; this is an agreement between the TP and their customer) is inconsistent, then it will also affect the computed data.

It is another special case where the customer is under the franchise of Meralco. This will be considered in RCOA implementation.

Market Network Model (PEMC – MTNL01)

In some cases, the selection of monitoring points in the MNM does not allow for most accurate representation of physical losses on the network, in particular, between metering installations and MTN in particular.

In other words, metering points can be allocated to distant MTN which, in turn, results in the calculation of losses and load adjustments that are not consistent with physical flows of energy on the network. *Please refer to Appendix 11: Market Network Model Analysis for the details of the observation noted by the review team.*

It should be noted that the loss adjustments calculated by the SSLA procedure depend on and are theoretically always consistent with the MNM in use (whichever monitoring points are included in it). This observation is therefore primarily an MDOM problem and it concerns PEMC's TOPD more than BSMD.

However, implications on the SSLA procedure are not negligible. If the monitoring point nearest to a particular metering installation is not represented by a MTN, the SSLA procedure is not able to use it for its loss adjustment calculations and is forced to assign this metering installation to another, more distant MTN.

Risk Implication

If metering points are allocated to distant MTN the resulting calculations of losses and load adjustments computed by the SSLA procedure might be inconsistent with physical flows of energy on the network and might overestimate physical losses between these monitoring points and the MTN.

This is clearly not compliant with the requirement set in clause 4.5.2.2 of the WESM Rules.

Audit Limitation

It should be noted that this observation is our interpretation of information brought to our attention by BSMD's staff members during a brief conversation held on 14 or 15 of August 2012. During this conversation, the staff members mentioned a document that had been prepared and sent to PEMC's TOPD to support their point. It presented their concerns about the appropriateness of the selection of monitoring points in the MNM and gives examples of monitoring points that should, in their view, be included in the MNM. We were not able to confirm our interpretation or give concrete examples to substantiate our observation.

Current Practice

Generally, monitoring points on the grid are represented by MTN in the Market Network Model (MNM). Metering installations are then allocated to their nearest MTN for SSLA purposes.

The selection of a given monitoring point (in the MNM) is influenced by the ability for the Market Dispatch Optimization Model (MDOM) to model it and converge to a solution. In some cases when there is insufficient voltage support on the network around a monitoring point, convergence is less likely to occur if it is included in the MNM.

As such*, WESM Rule 4.5.2 Location of Metering Point states that the Metering Service Provider shall ensure that the metering point is located as close as practicable to the market trading node. The rule also state that the Trading Participant, the Network Service Provider and the Market Operator shall use their best endeavours to agree to adjust the metering data to allow for the physical losses between the actual metering point and the relevant market trading node.*

Recommended Practice

The review team is recommending that the MNM and the selection of its MTN should more accurately represent actual flows of energy between metering points and customers. MTN should be carefully chosen to represent all relevant flows of energy into or out of the power system. Their selection should not be dictated by MDOM's inability to converge and give solutions on some network configurations. We believe that this represents a shortcoming in the robustness of the current version of MDOM which the manufacturer should fix in due course.

Management Comments

While this is primarily not a BSMD issue to resolve, BSMD recognises that distant MTN locations can hinder the calculation of accurate SSLFs

As per official comments sent on November 29, 2012:

The MO does not select Market Trading Nodes (MTN) for inclusion in the Market Network Model (MNM) but only models /reflects existing facilities available in the network but only up to existing monitoring points. In the absence of monitoring points then this is where SSLA adjustments are made. The ability of the MDOM to model the MTN is not related in any manner to the computation of losses in the SSLA.

User Password Management (PEMC – ITGC05)

Passwords in both MV90 and POMAX were not configured to have an automatic reset setup for a time period.

All the Macro-based programs except LUZ_VIZ_CONVERSION PROGRAM NTH.XLS - a program used for market fees and WESM MET generation, used by Metering Department are password protected. However, such password is shared by all the Metering Senior Specialists.

Risk Implication

Passwords may have been shared / discovered by unauthorized persons thereby compromising the security of the data in the system. More so that the user access rights given to the end-user have administration and super user functionality. Unauthorized access to systems or sensitive information may be obtained by unauthorized users if passwords are not securely controlled.

Current Practice

For access to the PEMC's domain, DMS and WIMPSYS, a default password is provided to a first time user. Upon initial access, the user is requested to reset the password. According to the MSS, the system will require them to define a password with at least one number and one special character.

As per ISMS Policy Matrix (PEMC-ISM-2011.003) Control No 11.5 Operating System Access Control, Formal procedures and guidelines shall be established, implemented and monitored to enforce secure log-on and secure connection through user authentication, password management, use of authorized utilities only, session time-out and limited connection time for high risk systems.

Also, as per ISMS Policy Matrix (PEMC-ISM-2011.003) Control No. 11.3 User Responsibilities: Formal procedures and guidelines shall be established, implemented and monitored to educate and require users to practice good

security in the selection and use of passwords, ensure protection of unattended equipment and to adopt a clear desk and clear screen policy.

Recommended Practice

An enhancement in the system should be implemented that would allow auto-reset of password.

If enhancements are not possible due to vendor/contract limitations, the WBSS (the in-house application being developed by PEMC for Metering Processes) should have the capacity to set password auto-reset.

Also, since Excel documents cannot be configured in such a way that different user should have different passwords; we are recommending that the sheets should be protected from unauthorized changes, as much as practicable.

If certain cells needs to be updated every time the Macro programs are used for validation, the sheet may still be protected and allow users to edit certain ranges using another set of password.

Management Comments

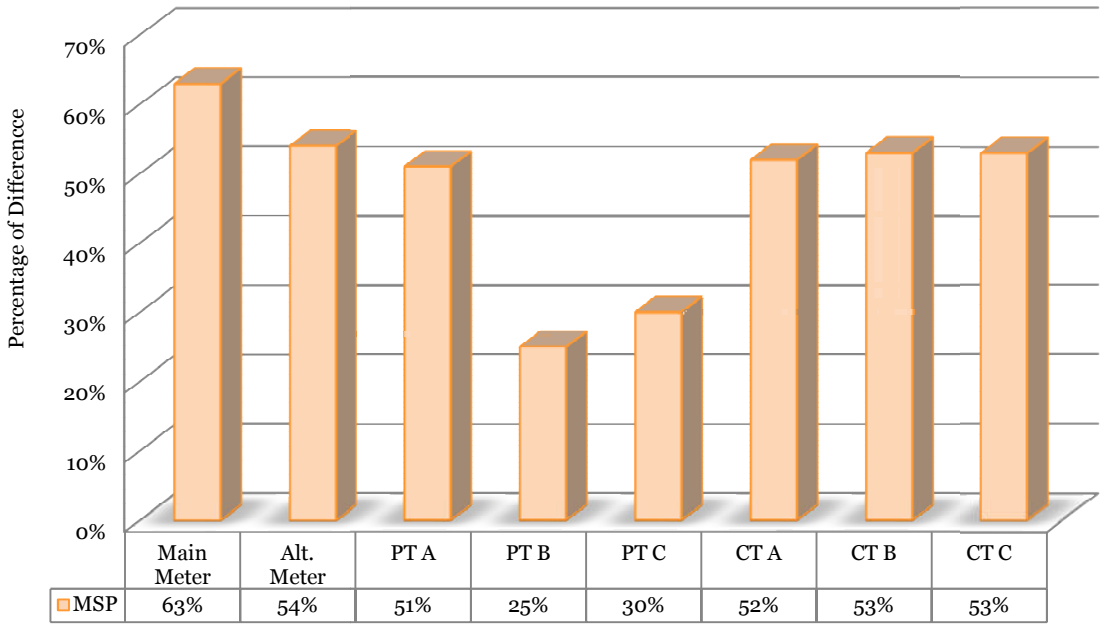
For both MV90 and Pomax system, there is no configuration to automate the password reset. This is addressed on the workstations/terminal of each metering senior specialist which is configured to have an auto-reset for an appropriate time period.

Password was incorporated into the program LUZ_VIZ_CONVERSION. This particular program is accessed, stored in one workstation only (password protected), and used by only one Metering Senior Specialist. However, password is no longer needed for each worksheet of all programs since versioning of programs is performed and are saved to archive whenever editing is conducted. Also, some worksheets serve as templates to be written automatically by the programs, hence, password would halt the execution of the programs.

Automatic password maintenance policy is written under Logical Access Management and not on the Clear Desk Clear Screen policy. IST affirms that the said systems have a limitation of resetting its password automatically. Therefore, IST included this on the Logical Access Exemption list report while workstations have a lockout period as required by the Clear Desk Clear Screen Policy.

Metering Installation Registration Form (MIRF) Record Keeping and Maintenance (MI – PI01)

Figure 18: Percentage of Discrepancies – "As found" vs. details on MIRF



	Main Meter	Alt. Meter	PT A	PT B	PT C	CT A	CT B	CT C
MSP	63%	54%	51%	25%	30%	52%	53%	53%

There is no formal policy that governs the monitoring of updates made to any installations in the metering sites. As such the following discrepancies were noted between the results of the physical inspection and the details in MIRF:

Main Meter: (average of 63% discrepancy)
132 out of 213 (62%) metering installations have discrepancies on the serial number
87 out of 213 (41%) metering installation have discrepancies on the meter make
186 out of 213 (87%) metering installation have discrepancies on the meter type

Alternate Meter: (average of 54% discrepancy)
108 out of 213 (51%) metering installation have discrepancies on the serial number
117 out of 213 (55%) metering installation have discrepancies on the meter make
118 out of 213 (55%) metering installation have discrepancies on the meter type

Potential Transformer – Phase A: (average of 51% discrepancy)
67 out of 213 (31%) metering installation have discrepancies on the serial number
118 out of 213 (55%) metering installation have discrepancies on the meter make
140 out of 213 (66%) metering installation have discrepancies on the meter type

Potential Transformer – Phase B: (average of 25% discrepancy)
44 out of 213 (21%) metering installation have discrepancies on the serial number
91 out of 213 (43%) metering installation have discrepancies on the meter make
21 out of 213 (10%) metering installation have discrepancies on the meter type

Potential Transformer – Phase C: (average of 30% discrepancy)
47 out of 213 (22%) metering installation have discrepancies on the serial number

65 out of 213 (31%) metering installation have discrepancies on the meter make
82 out of 213 (38%) metering installation have discrepancies on the meter type

Current Transformer – Phase A: (average of 52% discrepancy
81 out of 213 (38%) metering installation have discrepancies on the serial number
121 out of 213 (57%) metering installation have discrepancies on the meter make
132 out of 213 (62%) metering installation have discrepancies on the meter type

Potential Transformer – Phase B; (average of 53% discrepancy)
75 out of 213 (35%) metering installation have discrepancies on the serial number
128 out of 213 (60%) metering installation have discrepancies on the meter make
135 out of 213 (63%) metering installation have discrepancies on the meter type

Potential Transformer – Phase C: (average of 53% discrepancy)
78 out of 213 (37%) metering installation have discrepancies on the serial number
126 out of 213 (59%) metering installation have discrepancies on the meter make
133 out of 213 (62%) metering installation have discrepancies on the meter type

Risk Implication

Incomplete records maintained in MSP may signify that meter installations are not validly registered in WESM since there are no documents that would support its existence.

Also, not maintaining changes to the metering installation might lead to inefficiencies in tracking the status and physical condition of the components in the sites. Maintenance procedures may have been performed to legally invalid meter components due to records that are not updated.

Non-monitoring of the changes to the metering components may also lead to some operational inefficiency such as:

a. Useful life of the components are not properly monitored
b. MTR issues may not be tracked to specific components
c. Legal claims related to the metering installations may not be supported due to absence of acceptable document.

Current Practice

MSP uses Meter Installation Registration Form (MIRF) as a document to record a metering sites' institution and details of the instruments and all other equipments installed such as information on participant's delivery point, metering service provider, meter and meter devices, meter communication and WESM Metering Standards compliance evaluation.

MIRF is jointly accomplished by the head of Maintenance and Testing Division (MTD) and the trading participants, approved by the MSP Head and submitted to the MO.

Recommended Practice

A central database should be established to reflect or record historical information in MIRF and subsequent changes made to all metering installation. This database should be updated periodically and as the need arises.

Access should be provided both to the MSP and MO, however, applicable changes (edit function) to records should undergo proper approval process so that inadvertent / unauthorized changed to the records are prevented.

Request to change/update details of the metering installations should also undergo approval process (e.g. MTD staff inspect the physical condition of the metering installation and prepare reports, MTD head approves the changes made and forwards to MSD in Diliman, MSD will approve the document before it is translated into the database) which are all reflected in a single, standard document.

Management Comments

This observation will only be critical if the multiplier and the PT/CT Ratio have discrepancies between MIRF and Actual Inspection. MSP thinks that this can be mitigated thru a review of the procedures laid down in WESM Rules/Manual regarding the updates/revisions of the Metering Installation Information.

Also, some of the substations uses a form called Notice of Metering Installation Changes (NMIC) whenever there are changes to be made to the components installed in the sites.

MSP's point of view is that the data accuracy component in determining the level of non-compliance should be applied to the impact of the observation to the meter data used in settlement only.

Meter Seals Inventory and Log (MI – PI11)

There is no formal and documented Seal Monitoring process implemented across all MTDs. The following were observed by the review team:

a. The amount/volume of meter seal provisions distributed / issued to each staff and the range of serial numbers it contains were not traceable to any transfer document for accountability.
b. The serial numbers of seals pulled out from / returned to the stock room, and removed from / installed to the meter sites were not recorded and/or monitored for inventory purposes.
c. The serial numbers of the seals installed to the secondary terminals and instrument transformers were not recorded / monitored in any documents

Risk Implication

Seals are the primary control used by MSP to secure access to the meter installation. If unauthorized persons deliberately acquired unused seals and use the same to cover up pilferages being done, then accuracy of the meter data may be compromised.

Monitoring of the seals starting from the bulk transfer from the main warehouse, up to the persons responsible on securing both used and unused seals ensures that accountability controls are in place to protect not only the meter installation but also the misappropriation of the seals issued.

Current Practice

To provide security and track access, the MSP provision seals on the following components:

a. Revenue Meters (both main and alternate), specifically in the following components;

- Meter Terminal
- Demand Reset
- Test Block

b. Secondary Terminal Boxes of the instrument transformer

Seals installed to the revenue meters are recorded in the Polyphase Meter and Testing Report (PMTR), particularly in the "As found" and "As left" field of the report. However, no document is used to record/trace the serial number of the seal installed to the other components of the meter installation.

Commendable Practice

We highlight South Luzon South and North Luzon South's best practice of maintaining an Inventory Record of installed Meter Seals on a separate logbook with the reasons for changes indicated. This is in compliance with *WESM-MSDM-007, Section 2.9.1.6 Meter Seals and Padlock which states that the MSP shall maintain a record of the seal serial numbers and log subsequent changes including reasons for the seal change.*

Recommended Practice

An inventory monitoring procedure may be developed for the seals such as:

a. A document, similar to a stock card may be used (preferably electronically maintained) whenever a batch of seals is issued to each MTD staff. The volume, date of issue, and more importantly, the range of serial number should be recorded.
b. On a periodic basis (e.g. monthly), each MTD should report to the custodian the serial number of seals used supported by the PMTR or any other document prepared during preventive maintenance.
c. Seals removed from the metering sites shall also be returned to the custodian and accounted / recorded in the stock card.
d. The stock card, at a minimum, should contain the following details:

    - Serial number
    - Date issued
    - Person issued to
    - Status (e.g. unused, installed in the meter, removed from the meter, returned to the custodian)
    - Date returned
    - Document reference (e.g. PMTR number)
    - Reason for removal

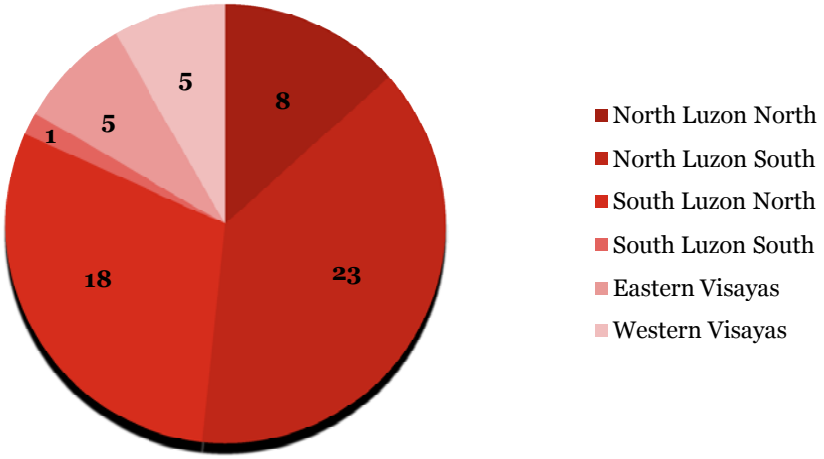
e. The unused seals on-hand per MTD should also be counted and reconciled to the current record of the custodian to ensure that no seals are missing, preferably on a quarterly basis.

Management Comments

Agreed.

Grounding Resistance on Instrument Transformers (MI – PI16)

Figure 19: No. of Sites with High Grounding Resistance



60 out of 216 (27.78%) sites visited have resistance measurement of more than 5 Ohms. Please note that due to the complexity of determining the Earth Fault factor per metering site location as required by Philippine Grid Code, Section 4.2.8 – Grounding Requirements, a spot check on the grounding installation was conducted instead. A maximum limit of 5 Ohms was used in determining the acceptable resistance level which is found suitable for industrial plant substations, buildings and large commercial installations. This is also in accordance with *IEEE Std 142-2007 Grounding of Industrial and Commercial Power Systems, Section 4.1.3 – Recommended acceptable values*.

Risk Implication

High resistance grounding installation exposes the Metering facilities to surges or direct lightning hit. Furthermore, it exposes the metering facility to the dangers of electric shock under normal and fault conditions.

Recommended Practice

It is recommended to have the grounding installation of highly resistive grounding facilities assessed for replacement or repair of grounding wires. To assure a stable grounding facility, a regular grounding check should be implemented by the MSP on the facilities.

Management Comments

As per MSP, these issues warrant further investigation because the results may be an indication of poor grounding resistance but are not conclusive.

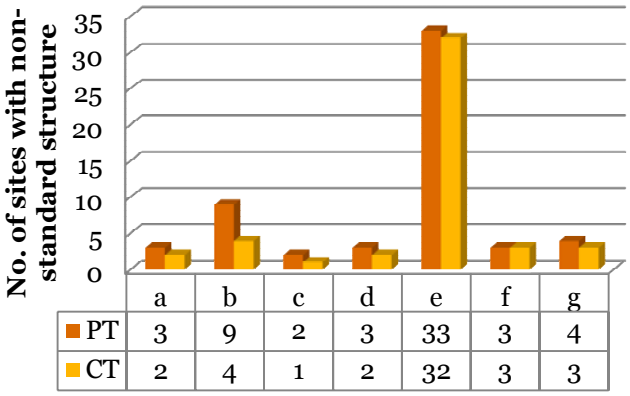
The manner of measurement used by the auditors is foreign to the MSP. They believe that the testing performed by the team was just a "quick check" and therefore not conclusive. This should not be considered as a major non-compliance.

Structure of Instrument Transformers (MI – PI15)

As illustrated in the figure below, we noted the inconsistencies against industry standard in the following metering installation structure components:

a. Terminal
b. Tank Casing
c. Primary Wires and Cables
d. Secondary Wires and Cables
e. Material on Secondary Conduit
f. Mounting Structure
g. Bushing

Figure 20: Non-standard structure on Instrument Transformers



	a	b	c	d	e	f	g
PT	3	9	2	3	33	3	4
CT	2	4	1	2	32	3	3

As per industry practice, these parts should be of a condition workable, acceptable by the industry and without any damage.

Please note that some of the metering installation uses polyvinyl chloride (PVC) pipe as a secondary conduit. It is not recommended to use PVC because this material can easily be penetrated by water and broken by strong force. Some of the PVCs have broken connection and uses electrical tape.

Also, some of these components are:

- Corroded
- Rusted
- Heavily oxidized with signs of fraying and discoloration
- Mounted on an elevated platform with rotten wood
- With traces of oil leak at the bottom/tank flance
- With exposed secondary leads.
- Have contaminated bushing (salt accumulation)
- Conduits found with breaks
- Wires are somewhat accessible
- Apparent exposure (outside conduit) of the secondary wires from box (sec term) to splicing box.

Risk Implication

Corrosion or deterioration of metering facilities affects the performance of the equipment upon a certain period of time. If the facilities are not well maintained, the data processing can be affected due to poor performance of the instrument transformers or revenue meters and other peripherals directly affecting meter readings.

Recommended Practice

MSP is recommended to perform the following corrective actions:

- Corroded tank casings and mounting structures should be repaired and painted
- Non-standard primary and secondary cables should be replaced by industry accepted materials.
- Replace the non-standard PVC Secondary Conduit with a Rigid Steel Conduit (RSC) which is sturdier and industry accepted material.
- Perform other necessary remediation to the structure components.

To ensure that these instances will not recur, we recommend for the MSP to implement the following controls:

- Include in the preventive maintenance activities various checks in the physical condition of the instrument transformer structure.
- Maintain a record of the results of the preventive maintenance including the meter installations' physical condition in a central database. This record should be able to track the remediation activities done if there are findings noted in each PM activity.
- Generate / prepare a report on a regular basis which monitors the number of meter installation which has outstanding PM finding and/or the number of days it is outstanding. This is to track how efficient metering staffs are in finding resolution.

Management Comments

This is a matter of the physical condition of PT/CT and just a maintenance issue.

Section 6: Other Observations

Calculations in Monthly Meter Trouble Reports (PEMC – VEE07)

Upon reproduction of the monthly MTRs for the 55th, 59th, 61st and 65th Billing period, we have found a number of Site Equipment Identification (SEIN) for which our calculations differed from BSMD. *Please refer to Appendix 2: MTR Calculation Testing Results*

for the details of the comparison made by the review team.

Risk Implication

The differences in results could potentially indicate inconsistencies in the issuance of the monthly MTRs. Such inconsistencies could lead to invalid meter data passing the monthly MTRs.

Audit Limitation

After submitting our initial observations to PEMC, we have been informed that the differences in data discovered by the review team had been amended before the final settlement of the accounts.

However, when the document requests are sent to BSMD, the data requested are supposed to be the files used for final settlement. With this, the general assumption is that, the review team performed its testing on the settlement-ready information.

Recommended Practice

We would recommend that PEMC keeps clearer record of the version of the metering data. Keeping track of a version number for meter data would allow PEMC to easily identify the change history of any data. Specifically we would suggest the following:

a. Introduce version control of data i.e. for each data interval introduce a flag that indicates whether the data constitutes

- Original Data
- Data substituted with an alternative meter
- Data substituted with RTU data
- Interpolated Data
- Estimated Data
- Data Based on historical data

b. Store data in a database and safe all data statuses to make all changes traceable and auditable

Management Comments

PEMC has indicated that the data has been updated before the final settlement. PEMC has also indicated that for the SEIN MF3MPALPGP201 the channels had been mistakenly interchanged in the POMAX database in the 61st Billing Period.

Meter Data Transferred via CD (NGCP – BPR01)

As per the covered period of the audit review, it has been noticed that the CD and the files inside the CD were not password protected. However, starting May 2012, password protection for the data has already been implemented.

Risk Implication

Unprotected data files may cause easy data manipulation that would greatly affect the result of PEMCs processes.

Recommended Practice

It is recommended to properly secure the data being transferred to PEMC to avoid unauthorized data access and to prevent unauthorized alteration of data.

Also, it is recommended for them to have a written guidelines on maintaining the level of password complexity requirements (i.e., password must be at least seven (7) characters in length and must contain at least one character from the given list of characters: (a) uppercase letter; (b) lowercase letter; (c) numeric character; and (d) special character) to reduce the likelihood of a successful password attack.

Management Comments

Password protection of electronic CD was already implemented in 2012 wherein the password is communicated to PEMC thru phone.

Environment to Test the System Changes in MSP (NGCP – ITGC05)

Testing of MV90 5.0 system patches was done in a single production workstation to ensure that the patch worked as intended and any adverse effect would be contained. This set-up indicates that there is no separate testing used.

If production and test environments are not separated, unauthorized changes or access to the production environment may occur.

Risk Implication

If production and test environments are not separated, unauthorized access to the production environment may occur.

Recommended Practice

Create separate production and testing environments for changes to the MV90 application, taking the following into consideration:

a. rules for the transfer of software from development to operational status should be defined and documented;
b. development and operational software should run on different systems or computer processors and in different domains or directories;
c. compilers, editors, and other development tools or system utilities should not be accessible from operational systems when not required;

d. the test system environment should emulate the operational system environment as closely as possible;
e. users should use different user profiles for operational and test systems, and menus should display identification messages to reduce the risk of error;
f. sensitive data should not be copied into the test system environment.

Management Comments

Changes in TIM files are applied on one production workstation for testing before applying to the rest of the workstations and not on the production server. The approved TIM files to be rolled-out to the rest of workstations will have a corresponding memo issued by MSD Head.

MSP agrees on the separation of environments. Currently (for the MV90 version XI), this is being addressed through the use of a stand-alone workstation (i.e. serves as a dedicated test bench), which is separate from the production environment.

Disaster Recovery / Business Continuity Plan in MSP (NGCP – ITGC06)

A disaster recovery plan (DRP)/business continuity plan (BCP) for MSG exists. However, it identifies the business recovery site(s) only and does not provide comprehensive guidelines in case of disaster. The DRP is dated June 1, 2006 and was prepared when NGCP was still known as Transco. This indicates that the plan is outdated and may no longer be suited to the current environment of NGCP. The plan was also never tested since it was implemented.

Risk Implication

Regular testing and updates decreases the risk that the business continuity plan may no longer be relevant or effective.

Recommended Practice

Create a new or updated BCP/DRP based on the results of a risk assessment, business impact assessment and recovery strategy selection. The business continuity planning process should consider the following:

a. identification and agreement of all responsibilities and business continuity procedures;
b. identification of the acceptable loss of information and services;
c. implementation of the procedures to allow recovery and restoration of business operations and availability of information in required time-scales; particular attention needs to be given to the assessment of internal and external business dependencies and the contracts in place;
d. operational procedures to follow pending completion of recovery and restoration;
e. documentation of agreed procedures and processes;
f. education of staff in the agreed procedures and processes, including crisis management;
g. testing and updating of the plans.

Management Comments

Pampanga will be the new DR site of Diliman for MV90 version XI. PEMC also has MV90, which could technically be the back-up of Diliman.

Testing of Backup Data in MSP (NGCP – ITGC08)

There are multiple meter data sources that are considered as backup data sources in case the MV90 system becomes unavailable. Backup data may be available but the procedures for requesting, retrieving and restoring data do not exist.

Risk Implication

Lack of or inadequate backup of critical business information or software increases the risk that in the event of system failure, the system cannot be fully restored to normal operation.

Current Practice

Metering data from MV90 are archived on a yearly basis and maintained in a production folder. While this may be considered backup data, such data are not tested for recoverability.

Recommended Practice

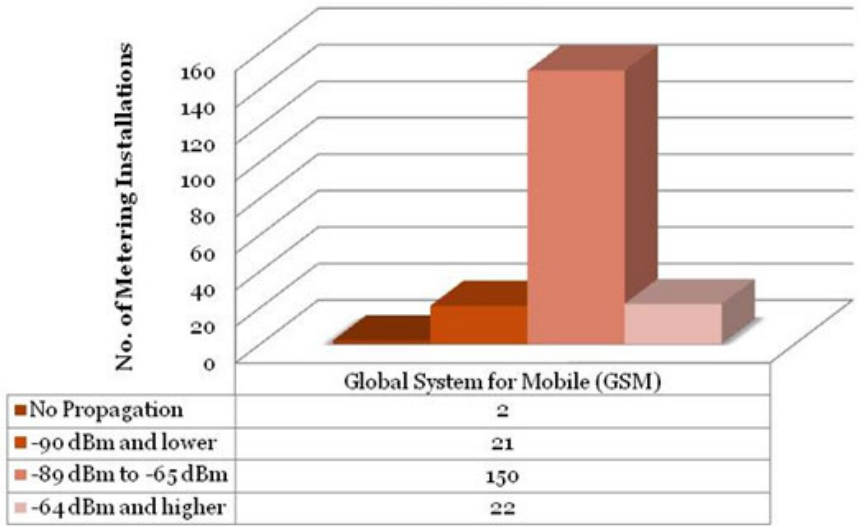
Include as a critical element of computer operations and business continuity the creation and implementation of backup policies and procedures for the MV90 system. Ensure that backup data and production systems are tested regularly for recoverability.

Management Comments

NGCP follows back-up and recoverability procedures in the WESM Manual (WESM-MSDM-MM-05 Metering Standards & Procedures, 6.9 "Emergency Procedures"), thus no need to create a separate policy/procedure.

Communication Link (MI – PI02)

Figure 21: GSM Communication Link



Out of the 195 metering installations that use GSM as a communication link, **2 or 1.03%** were noted to have no signal propagation; **21 or 10.77%** have intermittent to weak signal; **150 or 76.92%** metering installations were noted to have good signal strength and **22 or 11.28%** have excellent signal strength.

Risk Implication

The metering sites that use GSM as communication link and which has no signal propagation, and/or signal strengths that fall below the minimum acceptable level (-90 dBm and lower) may result to failed or unsuccessful retrieval and transmission of meter data.

Extended period of failed transmission may likewise result to manual retrieval of meter data which defeats the purpose of automatic transmission, thus, may cause failure to operational efficiency in MSP.

Current Practice

Dedicated lines such as Digital Telephone Systems (DTS) use digital facilities to transfer data speedily through telephone lines while Global System for Mobile (GSM) mainly functions through a communications network signal measured in dBm or the power ratio in decibels (dB) of the measured power referenced to one milliwatt (mW).

Metering installations with signal strength propagations that fall between -90 dBm and lower values are considered "intermittent to weak" for remote data acquisition where drop calls happen or the network signal may break up. Signal strength propagations between -89 dBm to -65 dBm are considered "good" while values beyond -65 dBm are considered "excellent" for electronic data transmission.

In the Philippines, while the DTS operation is split between PLDT, BayanTel and other dedicated telephone lines, the GSM systems used by the MSP are entirely operated by Smart Communications, Inc.

Recommended Practice

To properly manage the communication problems encountered by the metering facilities, a conduct of study is recommended on the selection of the most suitable communication link for a certain metering point.

Along with the other aspects, the major factors to be considered in the application of the most suitable communication link are the performance of the communication medium, the costs associated with installation and maintenance, the location of the metering facility, and the advantages and disadvantages of using the communication link.

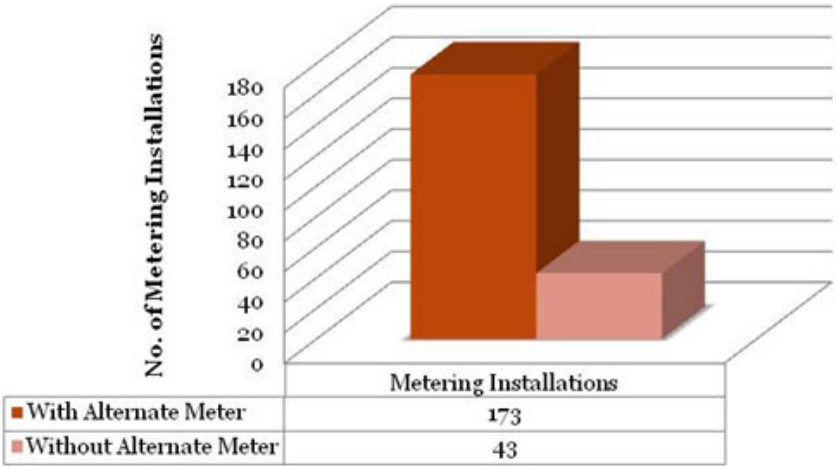
Upon weighing the factors enumerated, a consideration may be made on the selection of the most suitable communication link out of the practices of other electricity markets such as the use of General Packet Radio Service (GPRS), wireless communication, a dedicated Digital Telephone System (DTS), a Global System for Mobile (GSM), a power line carrier or any other equivalent technology.

Management Comments

Agreed.

Alternate Meters (MI – PI09)

Figure 22: Absence of Alternate Meter



It was discovered that **43 out of 216 (19.91%)** metering facilities visited have no alternate meters installed.

WESM-MSDM-MM-007 Metering Standards and Procedures, Section 5.3.1.1 -Registration and Submittals states that one of the three types of Metering Installations to be registered is: "Main and alternate meter, of revenue quality meters, with the same accuracy class and features. The alternate meter is not mandatory."

However, it is a good practice to have an alternate meter as a component of the metering facility for Validation, Estimation and Editing (VEE) purposes. Whether the metered data contains missing values, uncertain values or exceeds the maximum or minimum values, such data shall undergo validation, estimation and editing wherein substitutions of metered data should follow the established policy using historical data or the best available information.

Risk Implication

The alternate meter data serves as substitute in the Validation, Estimation and Editing (VEE) process whenever the validation procedures indicate that the main meter data might be incorrect. If the alternate meter (and data) is not available, the estimate shall be prepared based on the historical load pattern. Although the historical load pattern is considered acceptable in the VEE process, the alternate meter data should be taken primarily into consideration since it measures a more reliable figure. Hence, as far as the VEE process is concerned, whenever the main meter data contain missing, uncertain or exceeding maximum values, the absence of an alternate meter (and the data it provides) affects the reliability of estimates since the historical pattern of the meter data would then be considered outright.

Recommended Practice

The installation of alternate meters that are of revenue type on all metering facilities should be implemented. The alternate meter data will serve as a back up whenever main meter troubles exist in the normal operation. These alternate meters should be compliant to the quality standards and the selection and evaluation of the equipment specifications may be made in relation to the set of criteria used by the MSP for the acquisition of main meters.

Dependent on the intention of WESM, the WESM Manual is recommended to be revised to include alternate meters as one of the requirements for WESM registration.

Management Comments

Agreed.

Accuracy of TOPD's RTU Averaging (PEMC – VEE02)

Upon inspection of the processes employed by Trading Operations and Planning Department (TOPD) to produce actual dispatch files, we found that the process of averaging was not as accurate an indicator of metering quantities as would be the case if an alternative approach was used to approximate energy consumption from the 5-minute RTU measurements, for example using a trapezoidal approximation.

The review team's observation only pertains to situations where the RTU data is in fact being used for estimation and substitution. In these cases inaccuracies would have an impact on customers. PEMC has indicated that it reviews the quality of the data in those specific situations where the RTU data is in fact used.

Risk Implication

Accounts could be settled incorrectly if inaccurate RTU meter data is used to substitute meter data.

Current Practice

Five (5)-minute snap shots of the RTU data are provided by TOPD to BSMD on a regular basis. In order for this data to be used as reference information for the masterfile changes in the SSLA process, it is averaged into hourly RTU quantities called actual dispatch files. TOPD provides actual dispatch files together with the snap shots.

To validate the actual dispatch files received, MMS perform the averaging process using a macro-based program and compare the results with the average provided by TOPD.

Recommended Practice

It is important to ensure RTU data used in metering is accurate; our recommendation is to continue work on the Software solution to develop a more accurate method for the averaging of RTU data.

We would suggest that this new solution takes into account the following issues:

a. The time stamps of the 5-minute data might not be exactly on the 5th minute.
b. Interpolation to make up for missing 5-minute values

Management Comments

TOD has pointed out that they have already recognized the need to enhance the averaging process, being aware that improvements can be made. TOD has in fact performed some preliminary investigations on this. It has indicated that they would be able to implement an enhancement before the end of the year.

PEMC's Internal Procedures on Checking the Accuracy of RTU averaging (PEMC – VEE03)

BSMD independently validates the actual dispatch files (average RTU data) calculated by TOPD and any discrepancy identified is communicated to TOPD. Once received, these discrepancies can result in a re-run procedure of the averaging program of TOPD. However, most of the time TOPDs original data is used irrespective of the discrepancies identified by BSMD.

Also, the results of the RTU Status Summary Report are not considered in averaging the snap shot.

Risk Implication

Errors in calculating the correct average hourly RTU value can lead to incorrect pro-rata allocations of meter quantities in cases where several MTN share one metering installation.

Recommended Practice

a. PEMC BSMD to communicate with PEMC-TOPD to centralise the process of averaging the RTU data.
b. Centrally conduct the averaging of RTU values with PEMC's TOPD department.
c. Ensure that TOPD is aware of BSMD's needs for the average RTU data and that the process of averaging is understood by all parties involved.

Management Comments

The agreement is that to submit the inconsistencies noted by BSMD to TOPD.

RTU Data Quality Flags (PEMC – VEE04)

The error flags of the 5-minute MMS snap shots are not considered during the RTU averaging process.

Risk Implication

The actual dispatch files (average RTU data) do not have any information on the data quality. Hence, average RTU received by BSMD may not be the accurate representation of the actual RTU reading due to inclusion of the snap shots with error flags. With this, any meter quantities that are determined using RTU data could potentially be flawed.

Recommended Practice

As the RTU data in some cases is used to apportion meter data, it is important to ensure its accuracy. We therefore recommend the process owner to validate / investigate the RTU measurements prior to applying them in the determination of final meter quantities.

PEMC has indicated that it checks the quality of 5 minute MMS data in cases where it is used for substitution of metering data. We would recommend that the quality flags of the 5 minute MMS data are taken into consideration when producing the average RTU values on an ongoing basis rather than on as needed basis.

Management Comments

Several validation and estimation processes, review and checks are conducted by Metering before the RTU values are substituted such as:

a. Generation of RTU graph determines if the RTU is good data.
b. Zero RTU value with MQ means error on RTU.
c. Comparison of both historical MQ and RTU values establish the factor for good MQ and RTU value.

Any discrepancy during validation, an MTR is generated for the particular metering point. Sometimes, Metering directly requires NGCP to provide and inform PEMC about the status of RTU value for a particular node.

Visual Comparison of the Load Profiles (PEMC – VEE05)

The procedural manuals for the monthly meter data validation (Step 5.42 in Manual on monthly meter data validation and meter trouble report issuance) lay out a procedure for a visual comparison of load profiles to identify historic maximum meter quantities. During our walk through sessions we found out that this visual comparison of load profiles was not carried out anymore.

After raising this observation with PEMC they have informed us that an alternate procedure is in place to ensure the validity of the meter data.

Risk Implication

We believe that if this process or another comparable process is not carried out there is a chance that unusual spikes in consumption might not be identified and invalid meter data may go undetected during the validation process.

Current Practice

On a monthly basis, NGCP provides BSMD with a CD containing the meter quantity for the covered billing period. This data is compared with the data records uploaded in POMAX. A macro-based is used to perform this process.

The results of this validation are manually summarized into a Summary Monthly MTR Report. This report shows SEINs with incomplete meter data, SEINs with complete data but different meter quantities and SEINs with no data at all. This report is forwarded to NGCP for resolution in a password protected excel file.

Recommended Practice

The review team's recommendations are to:

a. Develop an automated methodology to check whether historic maximum or minimum meter quantities have been exceeded. This could be in the form of a database query where the current days meter readings are compared to historic minimum/maximum readings. Such a query would be run on PEMC POMAX metering data warehouse database and for each meter extract the monthly maximum/minimum value and compare it to the results of another query that extracts the historic maximum/minimum values per meter (excluding the current month).

b. Update the metering procedure manuals to reflect the solution that PEMC has already implemented

Management Comments

Although the resulting procedure is to issue an MTR for metering points that exceeded the historically established min and max meter data, there are instances the registered meter data can be in the min/max range with defective metering data which cannot be detected.

Since the BSMD/Metering had developed a graphical chart comparing the sum meter values at the downstream location vis-a-vis the market trading node (for both generators and load meters), it frequently pinpointed the value that exceeded the maximum or minimum values of the meter registration and if any, a Meter trouble report is issued. This is an alternate validation for any spikes or drops in any meter quantity that may exist which will answer your apprehension.

Automation of Manual Comparison of Data (PEMC – VEE06)

In the process of issuing monthly MTRs there is a comparison between data delivered from NGCP and the data that PEMC has uploaded into its Metering Data Warehouse (MDW). While part of this process is automated, a large proportion of control checks are performed manually. After the automated component of the process of issuing MTR's has finished to run, the metering specialist will have to go through the result to determine causes for possible differences between NGCP and PEMC data.

Risk Implication

The manual component of checking this large amount of data could be susceptible to human error. Such an error could lead to delays in the processing of MTRs.

Recommended Practice

Automation of the process and potential integration into an integrated software solution to prevent potential errors caused by human intervention during the comparison of data received from MSD and PEMC. The process could be automated to a higher degree if database technology was used consistently throughout the process. The process could then be conducted in the following way:

a. An SQL query to find all time intervals and SEIN for which no monthly data has been received
b. For all time intervals where data has been received calculate the difference between daily data received and monthly data.
c. Produce monthly meter trouble report that contains:

- A list of all files for which data is missing
- A list of all files for which daily and monthly data differ

Management Comments

As per the official response sent by the MO on November 29, 2012, the issuance of a monthly MTR is automated.

Procedural Manual in MSP (NGCP – BPR02)

There is no formal documentation regarding the detailed process on generating Load Profile data that is provided to PEMC at month end.

Risk Implication

This may affect the operation of the process owners especially the new MSD employees who's involved in the same routine. A procedure where they can rely on how to use the program needs to be documented to be used as a formal point of reference.

Recommended Practice

NGCP should provide clearer procedures and instructions on how to use the macro based program to generate the Load Profile data at month end to be used as a formal point of reference by the employee/s tasked to do the same routine.

Management Comments

There's guidance and procedures provided but not to the very detailed level. We consider the Meter Data Validation System (MDVS) flowchart included in the manual as guidance for the process of Load Profile generation.

And for the new employees, we ensure that proper trainings are provided before they are assigned to do the function.

Formal Information Security Responsibilities for MV90 in MSP (NGCP – ITGC01)

Roles regarding the access administration of MV90 5.0 application, its operating system (O/S), and server were assigned to the AMR Luzon Section and OS/Server Administrator. While these functions have been accepted by the responsible persons, their acceptance was not documented and their specific responsibilities were not formally written. The same observation is also true for system operators and their roles and responsibilities on MV90 5.0 information security.

Risk Implication

Effective security requires accountability and the explicit assignment of responsibility to asset owners, custodians, providers and users of information.

Current Practice

Asset and information owners remain ultimately responsible for their asset/data.

Recommended Practice

Include in the job descriptions of MSD employees their individual responsibilities in securing MV90 data and information. Make sure that MSD employees formally signify their understanding and acceptance of such responsibilities.

Management Comments

NGCP acknowledges the observation and recommendation. However, they have some reservations and they have to further verify it with their actual Job Descriptions.

User and System Administration Policies for MV90 in MSP (NGCP – ITGC02)

The MV90 5.0 user registration and deregistration processes are in place. Granting of and removal of access in the system is based on valid business need as determined by the MSD Head and AMR Luzon and VisMin Section Heads. While such processes exist, written policies are not in place to serve as guidance for requesting, approval, and removal of access.

Risk Implication

Unmonitored access control may lead to unauthorized access and reduced control over sensitive information or applications.

Current Practice

The creation, modification, and deactivation of user access in MV90 are driven by employee movement within the MSD. User access administration procedures are based on the MV90 User Guide provided by ITRON (vendor). These procedures are observed by MSD.

Recommended Practice

Given that the MSD will be implementing MV90 xi and will decommission the current system in the first quarter of 2013, we recommend the following:

MV90 5.0

a. for new accounts that would have to be created, make sure that these are authorized by the system owner and such authorization be documented (e.g. email).

b. for existing accounts that would have to be modified, make sure that the change is supported by a valid business need and duly authorized by the system owner.

c. for accounts that would be deactivated, make sure these are based on valid grounds (e.g. resignation, transfers) and deactivation is carried out on a timely basis.

MV90 xi

d. formalize policies and procedures for user and privileged access administration, taking into account the following:

- security requirements of individual business applications;

- identification of all information related to the business applications and the risks the information is facing;
- policies for information dissemination and authorization, e.g. the need to know principle and security levels and classification of information;
- consistency between the access control and information classification policies of different systems and networks;
- relevant legislation and any contractual obligations regarding protection of access to data or services;
- standard user access profiles for common job roles in the organization;
- management of access rights in a distributed and networked environment which recognizes all types of connections available;
- segregation of access control roles, e.g. access request, access authorization, access administration;
- requirements for formal authorization of access requests;
- requirements for periodic review of access controls; and
- removal of access rights

e. make sure such policies and procedures are approved, communicated and understood by all users and administrators.

Management Comments

Even if there are no formal policies in place, please note that no issues are discovered with regard to system and user administration during the audit. All of the user setup and setting in MV90 are valid and there are no gaps noted in the physical security of the server room and production area. No unauthorized staff has gained access to MV90 system as evidenced by the M90 Logs and the current MV90 system is on an isolated setup.

Password Configuration Settings for MV90 in MSP (NGCP – ITGC03)

MV90 5.0 has configurable password settings. It is equipped with the following password controls and values:

a. Maximum days password is valid - 0 (password never expires)
b. Maximum no. of login attempts - 10

The values assigned to the controls are not aligned with corporate password policy.

Risk Implication

Password settings that are not aligned to MSP's corporate policy may result in security breaches.\

Recommended Practice

Align the values of the existing MV90 password controls to those of corporate:

a. Maximum days password is valid - 90 days
b. Maximum no. of login attempts - 5

Use of available password controls at the operating system level may also help mitigate the risk of unauthorized access to the current MV90 application.

Make sure that MV90 xi would have adequate password controls that are also complemented by O/S level password controls.

Management Comments

Agreed.

Formal Change Management Policies and Procedures in MSP (NGCP – ITGC04)

An informal process for implementing MV90 5.0 system patches exists. During the time when vendor support was still in place, system patches provided by the vendor were initially tested in a single production workstation before it is implemented to the rest of the workstations. The roll-out is announced in a memo duly approved by the MSD Head. The last patch was installed in 2006 and since then, there have been no changes in the MV90 system. Note that the system is scheduled for decommissioning in the first quarter of 2013.

While this process worked in the past, there is no guarantee that such will work flawlessly for the new MV90 system. In addition, the new MV90 xi will likely have changes as it is used in operations. Without written policies and procedures for modifying systems, there is a risk that unauthorized changes will be made to information processing facilities.

Risk Implication

Without formal change control procedures, the risk that unauthorized or un-tested changes can take place, resulting in the corruption of information systems increases.

Current Practice

The MV90 application, a commercial proprietary system, has been in operation in NGCP since the early 2000's. According to the MSD Section Head, there are no formal policies and procedures for managing changes in MV90. The application is owned by the vendor and MSD does not initiate any code changes. While vendor support was still in place, the vendor provided MSD with system patches for implementation. Vendor support ceased in 2007 and since then, there are no changes to the current system.

Recommended Practice

Establish and implement formal change management policies and procedures for MV90 5.0 and MV90 xi to make sure that practices are standard across any and all types of changes (e.g. patch installation, major system upgrade, emergency/system recovery changes). Such policies and procedures, ideally, should encompass the following areas:

a. identification and recording of significant changes;
b. planning and testing of changes;
c. assessment of the potential impacts, including security impacts, of such changes;
d. formal approval procedure for proposed changes;
e. communication of change details to all relevant persons;
f. fallback procedures, including procedures and responsibilities for aborting and recovering from unsuccessful changes and unforeseen events;

g. segregation of duties.

Formal management responsibilities and procedures should be in place to ensure satisfactory control of all changes to equipment, software or procedures. When changes are made, an audit log containing all relevant information should be retained.

Management Comments

Configuration changes in MV90 are captured in the system log and are initially tested in one workstation before applying to the rest of the workstations. As for the program changes, the current NV90 version did not undergo any changes since 2007. The new version xi to be implemented, however, underwent a formal selection process such as proof of concept, supplier demonstration, etc.

Before meters are procured, MSD ensures that the suppliers are able to demonstrate that their meters can be interrogated by MV90 (i.e. compatibility issues should be satisfied). Otherwise, such meters will not be procured. It's the meter that should adapt to the MV90 system and not the other way around.

Audit Logs for User Activities in MSP (NGCP – ITGC07)

Audit logs recording user activities are not available in the current version of MV90.

MV90 5.0 captures the last login date and time of each user and administrator. This indicates that the system's logging capability is highly limited, posing a risk to the organization being unable to detect security breaches that may occur in MV90.

On a going concern, this may no longer be an issue for MV90 5.0 since an upgrade to MV90xi is expected to happen early 2013. However, audit logs, if available, should be enabled for the new MV90 (version xi) system due to the following factors:

a. MV90 xi environment will be part of the corporate domain thus losing the protection currently provided through isolation from the corporate network
b. Security Administration will be transferred to corporate IT.

Risk Implication

Without audit logs, it is difficult to achieve accountability of actions of users, third party services, and contractors. Furthermore, there is an increase risk of lack of evidence in case a security incident occurs.

Current Practice

MV90 has logs in place to ensure the integrity and availability of metering data. One of which is called validation log, which provides information on successful or failed validation procedures and communication log, which shows a record of communication errors between the metering points and the system.

Recommended Practice

Determine whether audit logs that record user activities, exceptions, and information security events are available in MV90 xi. If it is available, enable such logging facility and assign personnel that would perform regular log review.

Management Comments

Failures of the metering installations are captured by the Daily AMR Report which are forwarded to MO.

Since this is a limitation of the system, a log book is maintained by the metering dept. to record changes made by each operator.

Anti – Virus Software in MSP (NGCP – ITGC09)

The MV90 5.0 workstations and server are installed with Trend Micro antivirus software. However, it was noted that the virus definition files are outdated, the last update having been made in 2009.

Risk Implication

Not having effective protective measures against malicious code increases the risk of system unavailability, and/or destruction of data.

Current Practice

Sensitive and confidential data constantly travel through any organization's network. It is essential that adequate and effective controls be put in place to ensure the confidentiality, integrity and availability of these data.

Recommended Practice

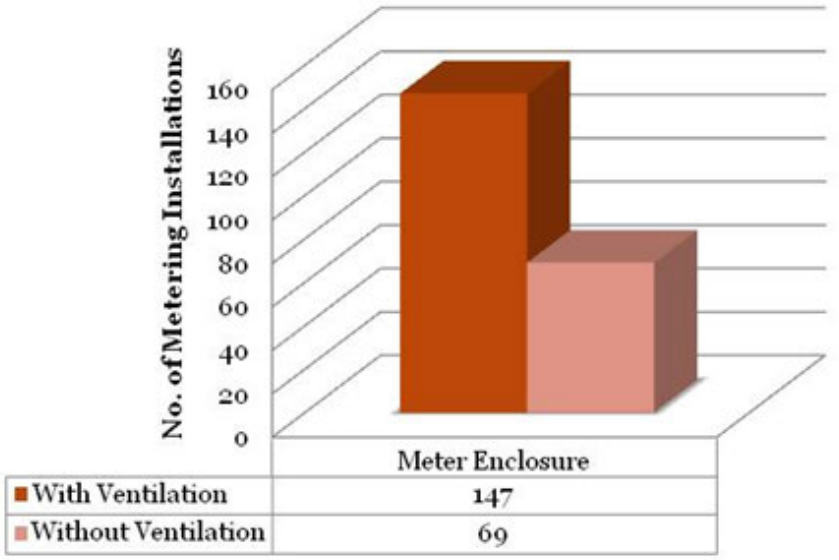
Update the antivirus software to the latest version, including virus definition files. Best practice dictates the implementation of policies and procedures to ensure adequate system protection and identification of potential security vulnerabilities.

Management Comments

Since MV90 is an isolated environment, there are minimal threats to the system and installation of antivirus is already being handled by the IT Department.

Ventilation (MI – PI06)

Figure 23: Inadequate Ventilation



It was discovered that **69 out of 216 (31.94%)** metering enclosures had no provision for adequate and proper ventilation.

Risk Implication

The primary risk associated with inadequate ventilation is the exposure to high temperature of the internal components installed in the meter enclosure. This situation may lead to overheating condition of the metering equipments and may consequently affect the measuring circuit and operation (e.g. burnt-out functional display) and ultimately, reliability of the of meter readings.

Recommended Practice

All meter enclosures are recommended to incorporate an adequate and proper ventilation feature to stabilize the changes in temperature. The ventilation may be in the form of perforated holes, slots or other forms of openings. It is important to note, however, that the size of the openings must be taken into consideration as it may allow the possible ingress of animals or any vermin infestation, water, excessive humidity and contaminants. Proper venting should be incorporated to allow meter operating conditions at**+55°C** and relative humidity (RH) of **95%**, non-condensing type.

Management Comments

Agreed.

Section 7: Opportunities for Improvement

OFI1 - Site Specific Loss Adjustment Process

The SSLA is a complex procedure that consists of a very large number of individual processes including a significant number of manual operations which are complicated and very susceptible to human errors. Such manual operations include:

a. Management and update of master files,
b. Manual selection and copying of large numbers of input and output data files,
c. Management and selection of template files,
d. Reverse engineering of circuit-breaker statuses and switching configurations (see next subsection),
e. Reconciliation of results generated with separate SSLA models,
f. Management of mapping file used to allocate meter quantities to MTNs etc.

Management may consider one of the following:

a. Improve the system currently in place by integrating individual processes,
b. Minimize manual operations/interventions
c. Replace dynamic site-specific loss factors with a set of fixed factors (for each switching configuration), or
d. Replace the system with an integrated commercial solution such as MV90 or POMAX.

We note that PEMC's BSMD is currently studying the feasibility of using fixed SSLF instead of dynamic SSLF.

OFI2 - Irregularities in Some Generated Daily SSLA Results

Analysing the sample SSLA data that was provided to us, we noticed a few irregularities in some of the results generated by the daily SSLA procedure.

These seem to have been introduced during manual interventions in the automated process that generates the daily SOURCE files (used by the SSLA calculation program) from the data files that are extracted daily from the POMAX database. Please see *Appendix 3: Irregularities in Daily Source Files*

for detailed explanation of the notes discrepancies.

PEMC's BSMD investigated these observations and determined that in each case the double counting was introduced by some manual intervention during the otherwise automated daily SOURCE file generation process.

BSMD's investigations also revealed that these irregularities observed on daily SSLA data had no impact on monthly SSLA data and therefore no impact on settlement calculations.

In light of these observations, PEMC might consider the following actions to improve the daily SSLA procedure:

a. Eliminate, as much as possible, the manual interventions that are meant to modify input data prior to re-runs.
b. Processes could be modified to allow input data to be generated and daily SSLA procedures to be run multiple times without manual intervention. This would be covered by the general proposal to improve SSLA processing.

c. Implement (and incorporate in the daily SSLA procedure) automated data checks on the daily SOURCE files. A simple record count for each meter and each hour would have picked up all the instances of double counting.

OFI3 - SSLA Template File Maintenance

The SSLA program generates the following two types of output files:

a. *SSLA All Data* output files contain raw measured loads, adjusted loads, line losses, transformer core and copper losses, and SSLF for a whole day. Daily data contained is in *SSLA All Data* Output files generated during the monthly SSLA procedure is used in settlement.
b. *Adjusted Energy* output files only contain adjusted loads for a whole day. These files are not used in settlement.

To generate results, the SSLA program requires a separate template file for each type of output files: the *SSLA All Data* template file and the *Adjusted Energy* template file. These template files provide information on the current SSLA run such as the list of meters that need to be processed for each hour in a given day. Our understanding is that template files are maintained and updated manually.

Reviewing the sample of monthly SSLA data provided to us we have observed a number of irregularities caused by an outdated SSLA All Data template file or an outdated Adjusted Energy template file (or both). Please refer to *Appendix 4: Outdated Template Files*

for the details of the irregularities observed.

Clearly, the implications of a meter ID missing in a template file is that the results for the meter in questions are not generated in the corresponding output file. In the case of the *SSLA All Data* template file it also means that settlement calculations for the given meter cannot take place.

PEMC's BSMD investigated these issues and determined that in all cases, irregularities were either observed in results files that are not used for settlement (i.e. in *Adjusted Energy* results files) or in results files that can be used for settlement (i.e. *SSLA All Data* results files) but that were generated by preliminary SSLA runs only. In other words, irregularities observed in *SSLA All Data* results files were corrected in subsequent runs and therefore none of the observed irregularities were passed on to settlement.

In light of these observations, management might consider taking the following steps to improve the overall robustness of the SSLA procedures:

a. Implement some logic to automatically update template files to reflect changes in master files.
b. Use only one type of template file to generate both types of results files or; since they are not used in settlement, discontinue the generation of Adjusted Energy results files altogether.

We note again that this suggestion would be subsumed in the proposal to upgrade SSLA processing by eliminating spreadsheet template files.

OFI4 - Determination of Switching Configuration

The statuses of circuit-breakers in the system determine the configurations of the network and in turn the mapping between metering points and MTN that is used in SSLA calculations. However, we observed that these statuses are not provided by NGCP's Systems Operations Department (SOD) to PEMC's BSMD in a timely manner forcing BSMD staff to reverse engineer this information.

To determine the mapping for a particular MTN, BSMD's staff uses a trial and error method. To determine which switching configuration and/or mapping to be used, they visually compare the aggregated metering measurement curve to the plot of the RTU measurements taken at the MTN. The switching configuration is changed until one of the aggregated curves matches the RTU plot.

This process is manual and very susceptible to human errors and can lead to the mapping of metering points to incorrect MTN and therefore result in errors in the SSLA calculations.

NGCP's SOD stated that the statuses of the circuit breakers which are monitored by NGCP's SCADA systems would assist PEMC in determining network configurations. However, not all breaker statuses can be obtained. Some are monitored by other Distribution Companies and are not provided to NGCP's SO department while others are not monitored at all.

Further, NGCP's SOD currently provides PEMC with information on circuit-breakers at the transmission level (in their Energy Management System snapshot files) but not at the distribution level. The reason for this is that PEMC currently only requests the subset of SCADA data it needs for dispatch purposes.

We suggest that PEMC request NGCP's SOD to provide BSMD with status data for all circuit breakers under their supervision on a regular basis (preferably daily). These can be provided as separate files so as to not disrupt any processes already in place for dispatch purposes. For Distribution networks that the SOD does not monitor, the Distribution Utilities (DU) could be required to provide the information to NGCP's SOD or directly to PEMC.

OFI5 - Handling of Missing Data in Monthly SSLA Results

On various occasions, the text "*(#DIV/0!)*" was observed instead of non-zero numerical values in some output fields of the monthly SSLA results files (SSLA_All_Data_yyyymmdd.xls).

Table 8: Appearances of "(#DIV/0!)" in Monthly SSLA Output Data

Billing Period	Trading date	Hour	Runs	Meter ID	Output Fields
55	Jan 23, 2011	9	prelim final rerun	MF3MAMLNOR101 MF3MAMLNOR102	Adjusted Value (kWh) Line Losses (kWh)

Billing Period	**Trading date**	**Hour**	**Runs**	**Meter ID**	**Output Fields**
65	Nov 20, 2011	2	prelim	MF3MPNTAKEL05 MF3MPNTCAPE05	Adjusted Value (kWh) Line Losses (kWh) SSLF
65	Nov 25, 2011	11	prelim	MF3MAMLNOR101 MF3MAMLNOR102	Adjusted Value (kWh) Line Losses (kWh)

Note: the monthly SSLA procedure was run several times for each of the billing periods we have reviewed. Each run is given a name (prelim, rerun, final etc). These run names are given in the ***Runs*** *column.*

These files and, in particular, the 'Adjusted Value (kWh)' output field are used in settlement. We are not able to say what implications such text would have on settlement calculations.

After investigating this issue, PEMC's BSMD determined that the presence of the text in question "*(#DIV/0!)"* was due to missing equipment data in the Excel formulae calculating the corresponding results. According to the "Metering Standard and Procedures" WESM Manual, it is the NSPs responsibility to provide valid and accurate data for power transformers and conductors on the network between metering points and MTNs (refer to section 9.7 of this Manual). PEMC's BSMD stated that they regularly (every 6 months) request the MSD to provide a complete set of updated equipment data. However, it would appear the data provided by the MSD does not cover the entire set of equipments required in the SSLA procedure.

According to BSMD, observations had been detected and fixed with a "workaround process" in the monthly SSLA results actually used in settlement.

In light of this, PEMC might consider reviewing the methods of communication with the MSD to ensure all required data is available for BSMD to carry out the SSLA procedures. Further, the processes in place should be modified so that missing input data is detected and handled automatically.

OFI6 - Spurious Loss Adjustments

On November 5th 2011 at hour 10, the raw measured load present in the monthly SSLA output file (SSLA_All_Data_20111105.xls) for meter MF3MBLKMECO01 is 0kWh yet the corresponding line losses, copper losses, and adjusted values are non zeros and the resulting SSLF value is very suspicious (-342,723,443.724306). *Please see Appendix 7: Spurious Loss Adjustments for the details of the observation noted.*

PEMC's BSMD investigated these issues and determined that, in each case, the raw measured load for MF3MBLKMECO01 is in fact infinitesimal rather than zero. SSLA output files use a format (Excel format) that only captures an accuracy of up to nine decimal places which is the reason why infinitesimal raw measurements are recorded as zeros in the result files.

BSMD also confirmed that in each case, the calculated losses, adjusted load, and SSLF value were all consistent with the usual loss adjustment equations applied to the infinitesimal raw reading in question.

Although they might be consistent with the usual loss adjustment equations, we are of the opinion that the values taken by the SSLF in such circumstances are somewhat meaningless. All the numbers involved are very small and the calculations, although not incorrect, seem spurious.

PEMC might consider implementing some logic in the SSLA processes to remove spurious small values in raw data and for the corresponding SSLF to default to an unsurprising value, such as 1.0

OFI7 - Policies and Procedures Regarding Information Security in MSP

There have been a number of policies and procedures published by the Corporate IT Department of NGCP. The table below summarizes the IT policies pertaining to information security.

Table 9: NGCP's IT Policies and Procedures

Policy Document	Approver	Effective Date
Electronic Communications Usage Policy	President/CEO	December 2011
Portable Computing Device Security Policy	President/CEO	October 2011
User Password Policy	President/CEO	August 2011
Internet Usage Policy	President/CEO	March 2012
Confidentiality and Privacy Policy	These policies and procedures are under development.	
Confidentiality and Non-Disclosure Agreement		
Data Management Policy		
Information Classification Standard		
Network Security Policy		
Remote Access Policy		
Sensitive Data Handling Policy and Procedure		
System, Database and Application Administrator Policy		
Third Party Access Policy		
User Authentication and Authorization Policy		
User Malicious Software Policy		

All of the above stated policies pertain to the detailed implementation guidelines for the enterprise-wide information system security policy. The policy effectively provides for the following:

a. Purpose
b. Scope
c. Policy Statement
d. Roles and Responsibilities

- Users
- Managers
- Business owners
- Information Technology Department
- Information Technology Management
- IT responsibilities over technology resources

e. Coordination

f. Information Security Policy Administration
g. Definitions
h. Enforcement

NGCP's information security policy can be further improved by inclusion of the following elements:

a. a framework for setting control objectives and controls, including the structure of risk assessment and risk management; and
b. a brief explanation of the security policies, principles, standards, and compliance requirements of particular importance to the organization, including:

- compliance with legislative, regulatory, and contractual requirements;
- security education, training, and awareness requirements;
- business continuity management; and
- consequences of information security policy violations

OFI8 - Internal Review of the Operating Effectiveness of the Information Security Policies and Procedures in MSP

NGCP Management considers information security as vital to the company's viability and continued operations. The enterprise-wide information security policy includes a portion discussing the enforcement of the policy.

NGCP may further improve their process in creating a mechanism for ensuring compliance to policies such as:

a. The independent review should be initiated by management. Such an independent review is necessary to ensure the continuing suitability, adequacy, and effectiveness of the organization's approach to managing information security. The review should include assessing opportunities for improvement and the need for changes to the approach to security, including the policy and control objectives.
b. Such a review should be carried out by individuals independent of the area under review, e.g. the internal audit function, an independent manager or a third party organization specializing in such reviews. Individuals carrying out these reviews should have the appropriate skills and experience.
c. The results of the independent review should be recorded and reported to the management who initiated the review. These records should be maintained.
d. If the independent review identifies that the organization's approach and implementation to managing information security is inadequate or not compliant with the direction for information security stated in the information security policy document, management should consider corrective actions and possibly sanctions.

OFI9 - Policies and Procedures Regarding Remote Access Security in MSP

The policies and procedures for remote access is currently being developed.

While documentation is underway, NGCP may consider the following:

a. A policy should be formulated concerning the use of networks and network services. This policy

should cover:

- the networks and network services which are allowed to be accessed;
- authorization procedures for determining who is allowed to access which networks and networked services;
- management controls and procedures to protect access to network connections and network services;
- the means used to access networks and network services (e.g. the conditions for allowing dial-up access to an Internet service provider or remote system).

b. The policy on the use of network services should be consistent with the business access control policy.

OFI10 - Segregation of Duties in MSP

With regard to duties over the MV90 system, there are only two roles - user and administrator. The access rights for each role are based on documented job descriptions and the least privilege concept, resulting in conflicting duties being nil.

NGCP can further improve segregation of duties by establishing a formal access matrix, which may serve as guide to succeeding system administrators and reduce the risk of having unauthorized rights being assigned to users.

OFI11 - Review of Program Access Security in MSP

User and Administrator access to the MV90 system is supported by controls such as the isolation of the computing environment and effective segregation of duties. Incidentally, the limited number of MV90 operators and administrators had made administration fairly easy for MSD. These settings have not warranted that a review of program access security be performed in regular intervals. However, implementing such review may be necessary as and when the user base of the system increases significantly.

NGCP can further improve their process in conducting access rights review such as:

a. users' access rights should be reviewed at regular intervals, e.g. a period of 6 months, and after any changes, such as promotion, demotion, or termination of employment;
b. user access rights should be reviewed and re-allocated when moving from one employment to another within the same organization;
c. authorizations for special privileged access rights should be reviewed at more frequent intervals, e.g. at a period of 3 months;
d. privilege allocations should be checked at regular intervals to ensure that unauthorized privileges have not been obtained;
e. changes to privileged accounts should be logged for periodic review.

OFI12 - Password Management in MSP

The MV90 system does not provide for automatic assignment of passwords. The practice performed by the system administrator is to have new users enter passwords manually during account set-up. The system masks the characters as they are entered in the password field.

A way to improve the current practice is to consider the following requirements for user password management :

a. users should be required to sign a statement to keep personal passwords confidential and to keep group passwords solely within the members of the group; this signed statement could be included in the terms and conditions of employment;
b. when users are required to maintain their own passwords they should be provided initially with a secure temporary password, which they are forced to change immediately;
c. establish procedures to verify the identity of a user prior to providing a new, replacement or temporary password;
d. temporary passwords should be given to users in a secure manner; the use of third parties or unprotected (clear text) electronic mail messages should be avoided;
e. temporary passwords should be unique to an individual and should not be guessable;
f. users should acknowledge receipt of passwords;
g. passwords should never be stored on computer systems in an unprotected form;
h. default vendor passwords should be altered following installation of systems or software;
i. All users should be advised to:

- keep passwords confidential;
- avoid keeping a record (e.g. paper, software file or hand-held device) of passwords, unless this can be stored securely and the method of storing has been approved;
- change passwords whenever there is any indication of possible system or password compromise;
- select quality passwords with sufficient minimum length which are:
    - easy to remember;
    - not based on anything somebody else could easily guess or obtain using person related information, e.g. names, telephone numbers, and dates of birth etc.;
    - not vulnerable to dictionary attacks (i.e. do not consist of words included in dictionaries);
    - free of consecutive identical, all-numeric or all-alphabetic characters;
- change passwords at regular intervals or based on the number of accesses (passwords for privileged accounts should be changed more frequently than normal passwords), and avoid re-using or cycling old passwords;
- change temporary passwords at the first log-on;
- not include passwords in any automated log-on process, e.g. stored in a macro or function key;
- not share individual user passwords;
- not use the same password for business and non-business purposes.

OFI13 - Policies and Procedures regarding Physical Access Security in MSP

The following are the physical access and environmental controls in place for the MV90 data center:

a. Entrance is controlled by a biometric system (fingerprint)
b. Visitors are escorted by MSD personnel
c. Smoke detectors are installed
d. Existence of a fire extinguisher

The level of physical access and environmental controls implemented by an organization is based on perceived risks. While MSD may have comfort over existing controls, best practice suggests that:

a. the date and time of entry and departure of data center visitors should be recorded;
b. fire fighting equipment should be provided, tested and suitably placed;
c. guidelines for eating, drinking, and smoking in proximity to information processing facilities should be established;
d. environmental conditions, such as temperature and humidity, should be monitored for conditions, which could adversely affect the operation of information processing facilities;
e. uninterruptible power supply (UPS) to support orderly close down or continuous running of IT equipment supporting critical business operations;
f. emergency power off switches should be located near emergency exits in equipment rooms to facilitate rapid power down in case of an emergency;
g. emergency lighting should be provided in case of main power failure

OFI14 - Capacity Planning in MSP

The scalability of operations is dependent on an organization's ability to foresee and plan for future business requirements. In NGCP's MSD, the decision to increase capacity of existing resources (e.g. more workstations) is based on additional metering points dictated by customers' and TPs needs, and the efficiency and effectiveness of AMR operations, which is monitored on a regular basis.

NGCP may further improve their capacity planning process by considering the following:

a. For each new and ongoing activity, capacity requirements should be identified. System tuning and monitoring should be applied to ensure and, where necessary, improve the availability and efficiency of systems. Detective controls should be put in place to indicate problems in due time. Projections of future capacity requirements should take account of new business and system requirements and current and projected trends in the organization's information processing capabilities.

b. Particular attention needs to be paid to any resources with long procurement lead times or high costs; therefore managers should monitor the use of key system resources. They should identify trends in usage, particularly in relation to business applications or management information system tools.

c. Managers should use this information to identify and avoid potential bottlenecks and dependence on key personnel that might present a threat to system security or services, and plan corrective/preventive action.

OFI15 - Incident Management in MSP

Incidents involving the MV90 system were always referred to the vendor, ITRON, while paid support was still in place until 2007. After vendor support ceased, the MV90 Administrator handled incidents reported by the MSP. MV90 issues and fixes were listed in a logbook to serve as a reference and guidance in case of recurrence.

Management responsibilities and procedures should be established to ensure a quick, effective, and orderly response to information security incidents. NGCP should consider the following guidelines for information security incident management procedures:

a. procedures should be established to handle different types of information security incident, including:

- information system failures and loss of service;
- malicious code;
- denial of service;
- errors resulting from incomplete or inaccurate business data;
- breaches of confidentiality and integrity; and
- misuse of information systems;

b. in addition to normal contingency plans, the procedures should also cover:

- analysis and identification of the cause of the incident;
- containment;
- planning and implementation of corrective action to prevent recurrence, if necessary;
- communication with those affected by or involved with recovery from the incident; and
- reporting the action to the appropriate authority;

c. audit trails and similar evidence should be collected and secured, as appropriate, for:

- internal problem analysis;
- use as forensic evidence in relation to a potential breach of contract or regulatory requirement or in the event of civil or criminal proceedings, e.g. under computer misuse or data protection legislation; and
- negotiating for compensation from software and service suppliers;

d. action to recover from security breaches and correct system failures should be carefully and formally controlled; the procedures should ensure that:

- only clearly identified and authorized personnel are allowed access to live systems and data;
- all emergency actions taken are documented in detail;
- emergency action is reported to management and reviewed in an orderly manner; and
- integrity of business systems and controls is confirmed with minimal delay.

The objectives for information security incident management should be agreed with management, and it should be ensured that those responsible for information security incident management understand the organization's priorities for handling information security incidents.

OFI16 - Cryptographic Controls in MSP

Encryption is a standard feature of the current MV90 system. This ensures that the confidentiality and integrity of raw MV90 meter data traversing the NGCP network via ftp, is maintained.

To further improve cryptographic controls, MSP should consider the development of a cryptographic policy such as:

a. the management approach towards the use of cryptographic controls across the organization, including the general principles under which business information should be protected
b. based on a risk assessment and the required level of protection should be identified taking into account the type, strength, and quality of the encryption algorithm required
c. the use of encryption for protection of sensitive information transported by mobile or removable media, devices or across communication lines
d. the approach to key management, including methods to deal with the protection of cryptographic keys and the recovery of encrypted information in the case of lost, compromised or damaged keys
e. roles and responsibilities, e.g. who is responsible for:

- the implementation of the policy;
- the key management, including key generation

f. the standards to be adopted for the effective implementation throughout the organization (e.g. which solution is used for which business processes)
g. the impact of using encrypted information on controls that rely upon content inspection (e.g. virus detection)

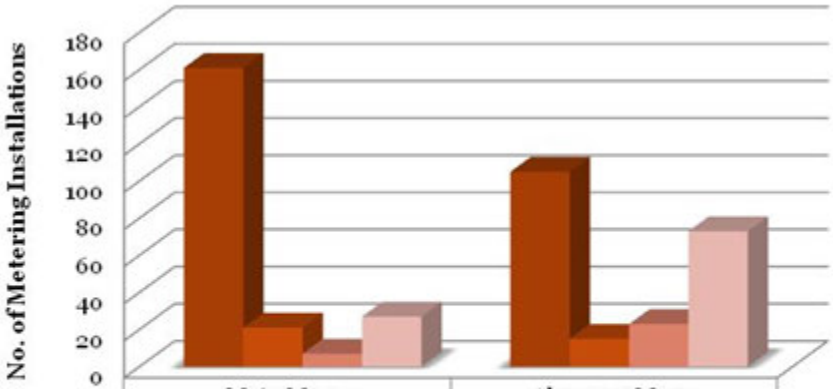
OFI17 - Preventive Maintenance Policies for the Metering Installation

WESM-MSDM-MM-07 Metering Standards and Procedures, Metering Service Agreement, Section 3.3 Provision of Metering Services requires the MSP to provide preventive maintenance activities to Customers as follows:

a. Meter reading;
b. Periodic inspections;
c. Metering security
d. Meter data communications service, including commercial telephone subscription;
e. Annual calibration and testing of meters;
f. Testing of instrument transformers as may be provided under the WESM Rules, furnishing the Metered Trading Participant with metered demand and energy consumption data, metering installation data and such other data as may be required by the MO

MTDs are primarily responsible for the health and integrity of metering equipments (i.e. instrument transformers and meter units). In addition, MTDs are mandated to take care of the whole metering installation including root cause analysis of problems encountered. However, these preventive maintenance activities and procedures, together with the definition of corresponding responsibilities, are not formally documented.

Figure 24: Compliance with Testing Schedules for Revenue Meters



	Main Meter	Alternate Meter
Compliant	161	105
Due for PM	21	15
No PM record on file	7	23
Not Applicable	27	73

Inspected the different preventive maintenance (PM) records and reports for revenue meters (both main and alternate) and noted that **21 out of 216 (9.72%)** sites have delays in PM schedules for the testing and calibration of the main meters, while **7 out of 216 (3.24%)** sites have no records of the most recent test conducted.

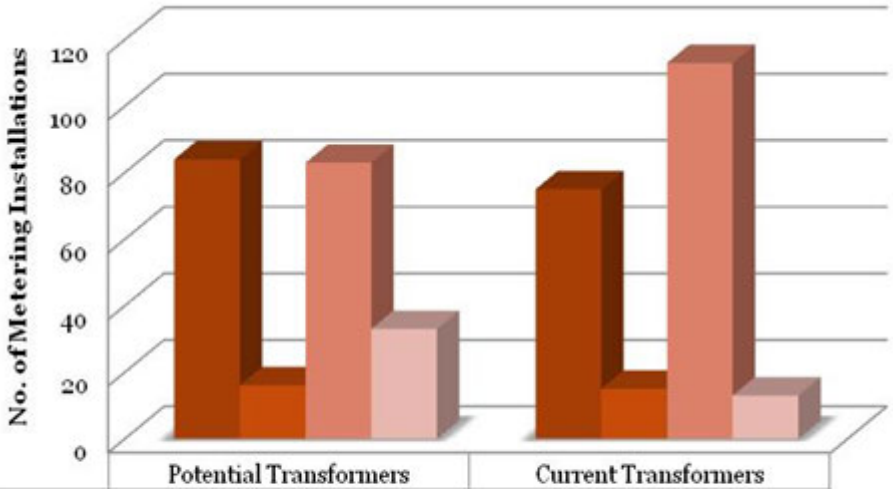
For the alternate meters, it was discovered that **15 out of 216 (6.94%)** sites have delays in testing and calibration schedules while **23 out of 216 (10.65%)** sites have no records of the most recent test conducted.

It should be noted that the baseline date used was the **physical inspection date of the review team** to calculate the delays in PM testing schedules. Also, revenue meters (both main and alternate) that were newly installed and are not yet subject to PM (1 year or less from the date of the physical site inspection) and metering sites with no alternate meters installed were included in the **Not Applicable** category.

The occurrence of delays in preventive maintenance schedules is not in accordance with the provision of the **Philippine Grid Code, Section8.4.2. - Meter Testing and Calibration** which states that **the Metering Service Provider and User, through the ERC or an independent party authorized by the ERC, shall test and seal the meters at least once a year and recalibrate or replace such meters if found to be outside the acceptable accuracy stipulated in the Grid Code.**

On the other hand, a record of the most recent test (and other preventive maintenance activities) conducted should be kept on file primarily for monitoring and tracking compliance with the annual preventive maintenance requirement and to document the results of the maintenance activities conducted.

Figure 25: Compliance with Testing Schedules on Instrument Transformers



	Potential Transformers	Current Transformers
Compliant	84	75
Due for PM	16	15
No PM record on file	83	113
Not Applicable	33	13

Inspected the different preventive maintenance (PM) records and reports for instrument transformers and noted that **16 out of 216 (7.41%)** sites have delays in PM schedules for the testing of the potential transformers, while **83 out of 216 (38.43%)** sites have no records of the most recent test conducted.

For the current transformers, it was discovered that **15 out of 216 (6.94%)** sites have delays in testing schedules while **113 out of 216 (52.31%)** sites have no records of the most recent test conducted.

The occurrence of delays in preventive maintenance schedules for testing is not in accordance with the provision of the **Philippine Grid Code, Section8.4.1.1 – Instrument Transformer Testing** which states that **Test on the Instrument Transformers shall be done by the Metering Service Provider or a party authorized by the Metering Service Provider, and the concerned User during the Test and Commissioning stage and then at least once every five (5) years or as the need arises due to questions on accuracy. The tests shall be carried out in accordance with this Chapter or an agreed equivalent international standard.**

It should be noted that the base measurement date used was the **physical inspection date of the review team** to calculate the delays in PM testing schedules. Also, instrument transformers that were newly installed and are not yet subject to PM (5 year or less from the date of the physical site inspection) and metering sites with no alternate meters installed were included in the **Not Applicable** category.

MSP should be more diligent in following the schedule of their testing and preventive maintenance activities for all metering installations and instrument transformers, in line with the Philippine Grid Code. In addition, results of such procedures should be documented accordingly.

If there would be any deviations in the scheduled testing activities of the metering installations and instrument transformers, these should be properly documented and included in revising their planned schedule to ensure they are not overlooked.

OFI 18 - Test Switch (previously MI – PI10)

WESM-MSDM-007 Metering Standards and Procedures, Section 2.9.1.5 – Meter Test Block/Switch, test block/switch shall be installed inside the meter enclosure to allow the current and voltage from each instrument transformer and each meter to be individually determined.

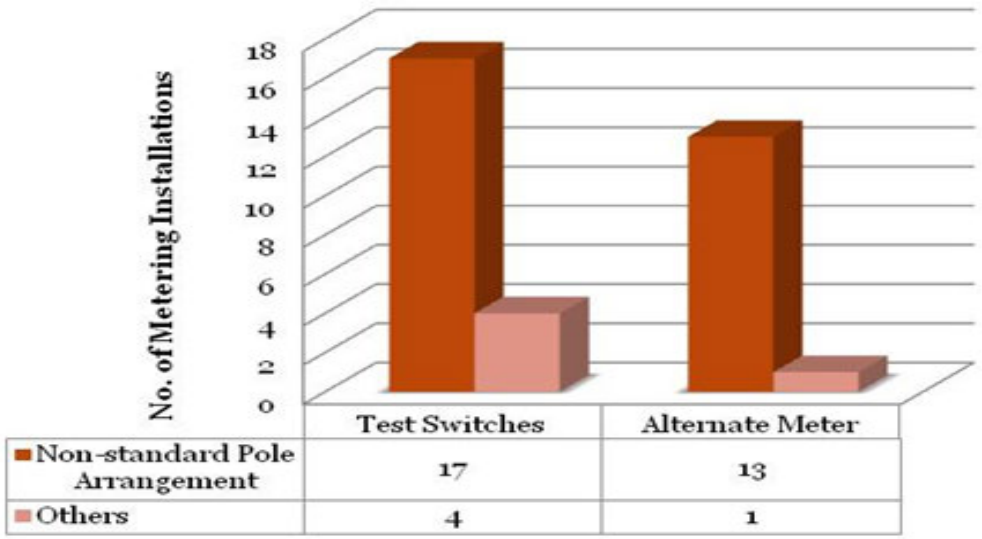
Technical Descriptions:

i. *Test Points: 10 points, (4 potential & 6 current Points)*
ii. *Pole Arrangement: P-CC-P-CC-P-CC-P*
iii. *Rating: 600 VAC, 20 amps*
iv. *Current carrying parts are made of non-tarnishing nickel silver*
v. *Switches are of the open knife-blade type*
vi. *Current switch poles are provided with an auto shorting jaw and the other has a shunted jack which is adaptable to a test plug*

It was observed during the physical site inspection that **17 out of 216 (7.87%)** main meter test switches have pole arrangements which may be an industry standard but a deviation from the WESM Manual while **4 out of 216 (1.85%)** have other issues like corrosion and loose connections.

On the other hand, it was discovered that that **13 out of 216 (6.02%)** alternate meter test switches have pole arrangements which may be an industry standard but a deviation from the WESM Manual while **1 out of 216 (0.46%)** was observed to be in a condition that needs immediate replacement.

Figure 26: Inadequate Test Switches



This may cause inefficiencies in isolating the meter installation to be tested or replaced purposes (i.e. hazardous operation).

MSP should implement a strict adherence to the existing technical requirements regarding the use of test switches and any existing preventive maintenance programs to ensure an acceptable degree of performance in the facilitation of testing procedures. If strict adherence to the standard technical requirements is not achieved, the departure (i.e. different pole arrangement), including any reason(s) for the departure, shall be recorded in the central information database of the metering installations so that a monitoring or review of the performance and operation of the industry-acceptable, but non-standard test switches may be facilitated efficiently in the future.

As mentioned, an implementation of a performance monitoring program should be considered to properly identify and assess the performance and condition of the test switches in service including the timely resolution of the issues.

Also, an improvement can be made on the implementation of precautionary guidelines on conducting tests using the test switches, which may include, but not limited to the following:

a. A list of step-by-step procedures in performing the test (e.g. removing test switch covers, opening the test switches, changing connections on live test switch, etc.), including the do's and don'ts during the testing; and
b. Proper communication and periodic updates of these guidelines across all MTDs performing the tests, in the form of e-mail, memorandum or even published hard copies that may be posted in the metering facilities.

OFI 19 - Instrument Transformer Type and Construction (previously MI – PI13 & MI – PI14)

WESM-MSDM-007, Sections 2.57 Current Transformer and 2.5.8 Voltage Transformer provides a minimum requirement as follows:

Items	*Current Transformer*	*Potential Transformer*
Type	*Outdoor Type* *Minimum oil filled* *Dry Type or Gas-filled*	*Outdoor Type* *Minimum oil filled* *Dry Type or Gas-filled*
Construction	*Single phase* *Wound type* *Free Standing*	*Single phase* *Inductive type* *Single bushing*

All the requirements stated above are complied with by the metering installations visited except for the following:

a. **23 out of 216 (10.65%)** metering installation have CT constructions which are deviation to WESM requirement
b. **34 out of 216 (15.74%)** metering installation have PT constructions which are deviation to WESM requirement

Current Transformer

The 10.65% CTs that are a deviation to WESM requirement are observed be of Bushing Type (indoor) instead of a Wound Type (outdoor).

As per industry practice, Bushing Type CTs are used for statistical and protection purposes only. This type in not particularly prescribed by WESM since it is required to be installed inside a primary equipment such as transformer or circuit breaker. With this setup, wirings cannot be easily determined or seen.

Potential Transformer

29 out of the 34 PTs that are a deviation to WESM requirement are observed to be Capacitance Potential Devices instead of an Inductive Type Transformer. According to the American Institute of Electrical Engineers (AIEE), these devices are not as accurate as the said transformers and may have undesirable transient inaccuracies unless properly loaded.

5 out of the 34 PTs that are a deviation to WESM requirement are observed to be constructed on a double bushing instead of single. WESM prefer single bushings to avoid confusion in connecting the live terminal to the ground.

Although all the Instrument Transformer inspected are noted to conform to the industry standard, thus no direct and/or indirect impact to the accuracy of the meter data and operational efficiency, this instances are still non-compliant to the explicit requirement of WESM Rule, specifically Sections 2.5.7 and 2.5.8.

WESM Manual may be revised to include industry acceptable instrument transformer type and construction provided that:

a. The specifications are still consistent with the quality standard intended by WESM
b. The environmental and physical factors are considered in the assessment

The instrument's intended functions will not be compromised

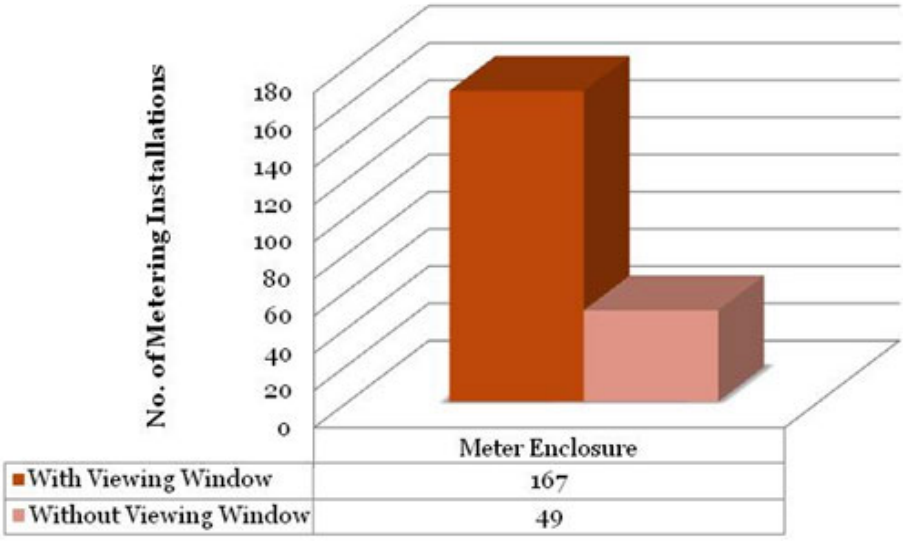
OFI 20 - Viewing Window – (previously MI – PI07)

Philippine Grid Code, Section 8.4.5.2 - Metering Equipment Security, the metering equipment cubicle shall be completely and securely locked and sealed, provided any register on the equipment is visible and accessible.

The primary purpose of the viewing window is to allow the metering services provider to efficiently inspect the condition of the meters and other internal components without the need to open the enclosure. Enclosures with viewing windows were actually used during the previous years, where manual readings are conducted.

It was discovered that **49 out 216 (22.69%)** metering enclosures have no viewing windows installed. This is not in accordance with the provision of the Philippine Grid Code, Section 8.4.5.2 - Metering Equipment Security which states that the register on the equipment shall be visible and accessible.

Figure 27: Absence of Viewing Window



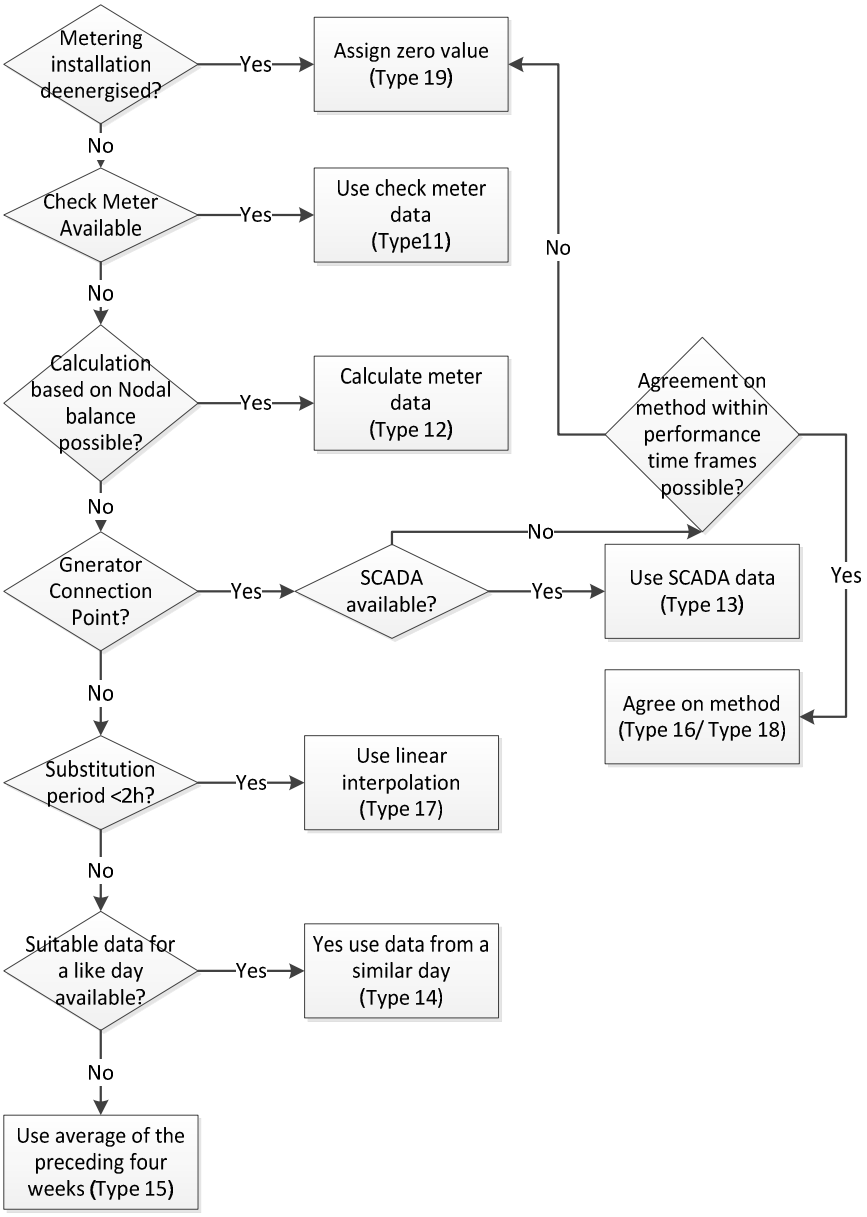
The absence or inadequacy of viewing window does not facilitate a visual accessibility to determine if a metering installation is functioning properly. Furthermore, the absence of a viewing window does not allow accessibility for the Trading Participants to inspect the condition of the meters especially that these meter enclosures are securely locked and technically, the TPs have no access beyond this point. The only way that TPs can check up on the stability of the meters is through the viewing windows.

To properly provide for a visible and accessible metering display, an adequate viewing window should be incorporated into the meter enclosure. The viewing window should be of a transparent high-grade engineering plastic equipped with a window cover for the purpose of mechanical protection, made of the same material as that of the meter enclosure. It is important to note that the overall structure of the viewing window must take into consideration the likelihood of ingress of animals or any vermin infestation, water, excessive humidity and contaminants.

Appendix 1: Preferred Substitution Method for Type 1 – 4 Metering Installations

Figure 50 lays out the process to be used by the MDP to decide which metering estimation or substitution technique is to be used for data that has not passed the validation procedures.

Figure 28: Decision Tree for Estimation and Substitution



Type 11 substitution:
The first choice for substitution of metering data for type 1-4 metering installations is the use of a check meter installation. If such an installation is available the MDP is to replace invalid data with data from the check meter for

the same trading intervals. Where the check metering installation is not located at the other end of a transmission line the MDP needs to adjust the data for transmission losses.

Type 12 substitution:
The MDP is required to calculate invalid interval data where there is no check metering installation available and a calculation based on a nodal balance is possible.

Type 13 substitution:
For connection points pertaining to generators and where SCADA readings are available MDPs are to use these to replace invalid data.

Type 14 substitution:
Where other substitution techniques are not applicable the MDP has to substitute invalid metering interval data with data for a similar day. Days to be used as a substitution are listed in order of preference in Table 12: Preferred Days for Data Substitution

Table 10: Preferred Days for Data Substitution

Day with data to be replaced	Preferred days in order of availability
Monday	Monday **
Tuesday	Tuesday** Wednesday**Thursday**Wednesday*Thursday*
Wednesday	Wednesday** Tuesday* Thursday** Thursday* Tuesday**
Thursday	Thursday** Wednesday* Tuesday* Wednesday**Tuesday**
Friday	Friday**
Saturday	Saturday**
Sunday	Sunday**

*Occurring in the same week as the day with the data to be replaced
**Occurring in the week preceding the day with data to be replaced

Type 15 substitution:
In cases where data for a suitable like day (type 14) is not available the MDP has to calculate substitution values based on the average of each corresponding interval from the preceding four weeks.

Type 16 & Type 18 substitutions:
For generator connection points where SCADA data cannot be used the MDP has to agree with the local network service provider (LNSP), the local retailer (LR) and the market participant on a substitution technique to be employed. Were alternate metering data can be used for minor adjustments or quality checks an agreed upon substitution is classified as a type 18 substitution.

Type 17 substitution:
MDPs may substitute invalid metering data through simple linear interpolation where the consecutive intervals to be substituted do not exceed 2 hours.

Throughout the process of data validation and substitution metering data is flagged with one of five meter data quality flags:

a. A for validated and accepted actual metering data
b. S for substituted metering data that is considered to be temporary
c. E for estimated data that is considered to be temporary
d. F for substitutions that are considered to be permanent
e. N for instances where no meter data exists

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Appendix 2: MTR Calculation Testing Results

Calculation of monthly aggregate metering quantity of metering CD data

In the process of issuing the monthly MTR PEMC's BMSD compares the monthly metered quantities as they are recorded in PEMC's POMAX database with the data delivered on CD by NGCP. For this purpose PEMC aggregates the 15minute meter data on NGCP's CD into a monthly figure.

IES has independently calculated the monthly aggregate meter quantities for the files on NGCP's CD provided by PEMC for the 55th, 59th, 61st and 65th Billing period. In the process we have identified a number of metering sites for which the calculation done by PEMC in the process of the monthly MTR does not match our calculations. We note that our calculations are based on the data we have been provided with in the folder "Data Requests 47,48,etc.,95\MSG CD" on CD 7 of PEMC's data transmittal.

Table 14, 15 and 16 list the Site Equipment Identification numbers of metering installations for which the monthly meter quantities calculated by IES and the ones calculated by PEMC in the process of issuing the monthly MTR do not match. The column "PEMC DEL" and "PEMC REC" list the meter quantities for delivered (DEL) and received (REC) quantities calculated by PEMC as stated in the monthly MTR[1]. Columns "IES DEL" and "IES REC" list the values independently calculated by IES.

55th Billing Period

Table 11: Non matching meter quantities on monthly metering CD – 55t h Billing Period

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3MMKAMAKA02	35,017,784	0	35,751,937	0
MF3MILAISE202	1,090,811	0	193,624	0

59th Billing Period

Table 12: Non matching meter quantities on monthly metering CD – 59t h Billing Period

SEIN	PEMC DEL	PEMC REC	IES_DEL	IES_REC
MF3MILIKIEL02	365,374,200	0	365,487,000	0

61st Billing Period

Table 13: Non matching meter quantities on monthly metering CD – 61st Billing Period

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3MITONIAA01			477	0
MF3MITONPCZ01			1,517	0
MF3MBTNSNRI01	152,328,514	16,214	153,575,023	32,427
MF3MBTNSNRI02	173,368,739	2,595	174,618,606	5,191
MF3MBTNSNRI03	173,027,124	3,299	174,323,121	6,597
MF3MBTNSNRI04	165,892,178	6,191	167,150,268	12,382
MF3MLMYBCCP06	1,249,800	4,800	1,590,051	4,800
MF3MLMYBCCP07	1,626,600	229,800	1,839,739	229,800

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3LMYBCCP08	1,505,600	1,600	1,746,732	1,600
MF3MSPCOSPC01	939,408	143,808	1,098,288	153,984
MF3MSPCOSPC02	979,104	132,480	1,123,440	138,048
MF3MPNTAKEL05	470,799	0	665,016	0
MF3MPNTANTE03	837,444	0	1,034,112	0
MF3MAMLAMLA01			49,532	84

Calculation of monthly aggregate value for POMAX data

For the process of issuing a monthly MTR PEMC aggregates metering data spooled from their POMAX database into a monthly figure. IES has independently calculated the monthly aggregate metering quantities for the data provided by PEMC in the folder "Data Requests 47,48,etc.,95\Monthly Spool for MTR from Pomax" on CD 7.

Table 17 and 18 list the Site Equipment Identification numbers of metering installations for which the monthly meter quantities calculated by IES and the ones calculated by PEMC in the process of issuing the monthly MTR do not match. The column "PEMC DEL" and "PEMC REC" list the meter quantities for delivered (DEL) and received (REC) quantities calculated by PEMC as stated in the monthly MTR[2]. Columns "IES DEL" and "IES REC" list the values independently calculated by IES.

59th- Billing Period

Table 14: Non matching calculation of monthly metering quantities spooled from the Pomax system – 59th Billing Period

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3MBOHBEIZ01	0	0	25,490	0
MF3MEPPEPPZ01	0	0	2,928,374	0
MF3MPNTCAPE02	0	0	770,616	1,764
MF3MGUITRAN01	0	0	345,995	3,916
MF3MCPPCPPC01	0	0	10,223,080	71,260
MF3MSCBSCBI01	0	0	1,529,174	16,191
MF3MLHELHEP01	0	0	448,839	262

61st – Billing Period

Table 15: Non matching calculation of monthly metering quantities spooled from the Pomax system – 61st Billing Period

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3MBOHBEIZ01	0	0	15769.2	0
MF3MSEVSEVI01	0	0	0	316.4
MF3MEPPEPPZ01	0	0	2729546.4	0
MF3MPNTCAPE02	0	0	844032	10080

SEIN	PEMC DEL	PEMC REC	IES DEL	IES REC
MF3MGUITRAN01	0	0	215683.65	3417.75
MF3MCPPCPPC01	0	0	8383480	74900
MF3MSCBSCBI01	0	0	1037496.6	35448
MF3MPALPGP201	26059810	0	0	26059810
MF3MLHELHEP01	0	0	567760.2	2.8

Appendix 3: Irregularities in Daily Source Files

On May 8 2011, the four kWh readings on meter MF3MBCNLUEL03 for hour 1 extracted from POMAX were as presented in the table below.

Table 16: POMAX Extract for MF3MBCNLUEL03 on May 8, 2011 Hour 1

Meter ID	Time ID	Minutes	kWh
MF3MBCNLUEL03-MUL	201118701	60	1680
MF3MBCNLUEL03-MUL	201118701	45	1701
MF3MBCNLUEL03-MUL	201118701	30	1729
MF3MBCNLUEL03-MUL	201118701	15	1750

Note: data extracted from POMAX is 15-minute data. The 201118701 time ID means: year 2011, week 18, day 7, hour 1 (or May 8th, 2011).

After conversion, the corresponding daily SOURCE file had eight kWh readings (instead of four) for meter MF3MBCNLUEL03 at 1:00 AM. These source file readings are given in the table below.

Table 17: Daily SOURCE File Readings for MF3MBCNLUEL03 on May 8, 2011 Hour 1

Reading ID	Year	Week	Day	Hour	Min	Value
MF3MBCNLUEL03-KWHD	2011	18	7	1	15	1750
MF3MBCNLUEL03-KWHD	2011	18	7	1	15	1750
MF3MBCNLUEL03-KWHD	2011	18	7	1	30	1729
MF3MBCNLUEL03-KWHD	2011	18	7	1	30	1729
MF3MBCNLUEL03-KWHD	2011	18	7	1	45	1701
MF3MBCNLUEL03-KWHD	2011	18	7	1	45	1701
MF3MBCNLUEL03-KWHD	2011	18	7	1	60	1680
MF3MBCNLUEL03-KWHD	2011	18	7	1	60	1680

Note: Each reading ID is made of two parts. The first part is a meter ID. The second part indicates the type of measurement. KWHD means "real power delivered to the customer" while KVARD means "reactive power delivered to the customer".

Quite obviously, each reading extracted from POMAX had been doubled up in the resulting Source file. Similar instances of apparent double-counting for meter MF3MBCNLUEL03 were observed in the data for the entire day on May 8, 2011 and occasionally on some other days. All instances of apparent double-counting for this meter observed on the daily SSLA data samples provided to us are listed in the following table.

Table 18: Instances of Double-Counting Observed for MF3MBCNLUEL03

Reading ID	Trading date	Hours
MF3MBCNLUEL03-KWHD	May 5, 2011	1
MF3MBCNLUEL03-KVARD	May 5, 2011	1
MF3MBCNLUEL03-KWHD	May 8, 2011	1 to 24
MF3MBCNLUEL03-KVARD	May 8, 2011	1 to 24
MF3MBCNLUEL03-KWHD	May 9, 2011	1
MF3MBCNLUEL03-KVARD	May 9, 2011	1
MF3MPGBPAGB04-KWHD	Nov 24, 2011	16

Unfortunately, none of these instances were picked up by any of the following processes in the daily SSLA procedure. For instance, in the particular case of hour 1 on May 8 2011, the results from the daily SSLA procedure for meter MF3MBCNLUEL03 were: raw value = 13,720 kWh, i.e. 2 x (1680 + 1701 + 1729 + 1750) and adjusted value = 13,720.18 kWh (which is around twice what it should have been).

PEMC's BSMD investigated these observations and determined that in each case the double counting was introduced by some manual intervention during the otherwise automated daily SOURCE file generation process. In the case of meter MF3MBCNLUEL03, some input data had been missing at the time when daily SSLA runs were performed and manual intervention had been required to modify input data and re-execute incomplete daily SSLA runs before the end of the billing period when data for that meter became available to BSMD. In the case of meter MF3MPGBPAGB04, manual intervention had been required to recreate input data for the daily SOURCE file generation process after the connection to the POMAX server had been lost.

Appendix 4: Outdated Template Files

Below is the list of instances where irregularities noted were due to outdated template files

1. As of the beginning of the 55th billing period (December 26, 2010), meters MF3MBCLVRES05 and MF3MBCLVRES06 were renamed MF3MCADVRES05 and MF3MCADVRES06 respectively.

   The corresponding *SSLA All Data* template files were updated accordingly but for the entire 55th billing period (December 26, 2010 to January 25, 2011), the old meter IDs were still used in the *Adjusted Energy* template files. This impacted daily and monthly *Adjusted Energy* results throughout the billing period.

2. Up until the 55th billing period, meter MF3MEAUEAUC01 was shared between a generator (EAUC) and a load (MEPZ). The meter would record positive values to measure net injections and negative values in case of net drawings. As of the beginning of the 55th billing period, a new meter (MF3MEAUMEPZ02) dedicated to the MEPZ load was added. Being a load-end meter, positive readings should have now indicated power drawings from the grid (and negative readings power injections).

   The monthly SSLA procedure was run several times for the 55th billing period, each run using different template files. In all runs, the *Adjusted Energy* template file was partially updated to reflect the inclusion of the new load-end meter (that is the new meter ID was included but readings were all negative indicating power injections rather than power consumptions). For two runs, the *SSLA All Data* template file was not updated at all (the new meter ID was not included) and for the other two runs performed that month, it was partially updated (the same way the *Adjusted Energy* template file was).

3. As of the beginning of the 55th billing period, meter MF3MLHELHEP01 was added to account for a generator embedded to another generator. Although generators reading are normally not adjusted by the SSLA procedure, it had been agreed between the different parties at stake that this one should be included in the procedure (in an effort to be fair to the host generator).

   Out of the 4 monthly SSLA runs performed for the 55th billing period, the *SSLA All Data* template file was properly updated to include the new meter ID in only two runs (the new meter ID was not included in the other two runs). The *Adjusted Energy* template file was never updated (the new meter ID was not added).

Appendix 5: SSLA Calculation vs. SSLA Models

Example 1

According to the master files associated with the preliminary SSLA run for the 59th billing period, the applicable SSLA model between hour 14 on May 11, 2011 and hour 8 on May 16, 2011 is SSLA model number 12 (noted '20110511_HR14-20110516_HR08'). Consequently, preliminary loss adjustments should have been calculated with SSLA model number 12 between hours 14 and 24 on May 11, 2011.

In actual facts, preliminary results contained in reconciled result file for hours 14 to 24 on that day coincide with the results generated with SSLA model number 12 for all meters except for the SEIN listed below:

MF3MBAGPENE20
MF3MBAGPNPN01
MF3MBAGPNPP01
MF3MBTPPENE18
MF3MBTPRGSI01
MF3MDARALEC04
MF3MDARALEC05
MF3MDARALEC09
MF3MDARBICO01
MF3MDARGFCC01
MF3MDARPHIZ01
MF3MHERPENE09
MF3MHERPENE11
MF3MHERPENE13
MF3MHERPENE14
MF3MHERPENE15
MF3MHERPENE16
MF3MMORBTPI01
MF3MMORPENE21
MF3MNLUCAS301
MF3MNLUCAS302

For these meters, reconciled results for hours 14 to 24 coincide with the results generated with SSLA model number 11 (noted '20110511_HR09-20110511_HR13') which, according to the associated master files is the applicable model between hours 9 and 13 on that day.

We note that another SSLA run (noted 'final') was carried out for the billing period in question. It is possible that irregularities observed in the preliminary results were corrected in the final run. However, we were not able to confirm this as we were only provided with reconciled results for the final run (that is we were not provided with the results generated with the separate SSLA models and therefore we were not able to assess if reconciled results were consistent with the sequence of applicable models).

Example 2

Similar irregularities were also observed in the reconciled results for July 7, 2011. According to the master files associated with the preliminary SSLA run for the 61st billing period, the applicable SSLA model between hour 15 on July 7, 2011 and hour 5 on July 9, 2011 is SSLA model number 6 (noted '20110707_HR15-20110709_HR05). Consequently, preliminary loss adjustments should have been calculated with SSLA model number 6 between hours 15 and 24 on July 7, 2011.

In actual facts, preliminary results contained in reconciled result file for hours 15 to 24 on that day coincide with the results generated with SSLA model number 6 for all meters except for meter MF3MBINBHEP04.

For this meter, the results (i.e. calculated line and transformer losses and adjusted meter quantities) as well as the input data (i.e. raw meter quantities) contained in the reconciled result file for hours 15 to 24 coincide with the data associated with SSLA model number 5 (noted '20110706_HR01-20110707_HR14') which, according to the master files is the applicable model between hour 1 on July 6, 2011 and hour 14 on July 7, 2011.

We note that another two SSLA runs (noted 'rerun' and 'final') were carried out for the billing period in question. It is possible that irregularities observed in the preliminary results were corrected in these additional runs but again, we were not able to confirm this as we were not provided with the right results files for these runs. Files generated with a unique SSLA model covering the entire billing period were provided when according to associated master files; some 19 SSLA models were in fact used.

Appendix 6: Adjusted MQ vs. SSLF

The table below shows some examples of this observed on November 25, 2011.

Table 19: Inconsistencies between Adjusted Loads and SSLF

Meter ID	HOUR	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MBOHBLCI03	1	6034.0	5800.5	233.5	0.0	0.0	1.039	7UBAY_T1L1	BLCI111
MF3MBOHBOH104	1	346.5	334.5	12.0	0.0	0.0	1.035	7UBAY_T1L1	BOHECO1
MF3MGARPMSC01	1	63.0	61.4	1.6	0.0	0.0	1.026	7UBAY_T1L1	PMSC_BO
MF3MUBABOH201	1	1601.6	1555.4	41.0	4.1	1.1	1.029	7UBAY_T1L1	BOHECO2
MF3MUBABOH205	1	1333.5	1311.6	21.9	0.0	0.0	1.016	7UBAY_T1L1	BOHECO2
MF3MUBAMARC01	1	920.5	915.9	4.6	0.0	0.0	1.005	7UBAY_T1L1	MARCELA
MF3MBOHBLCI03	2	5726.0	5516.3	209.7	0.0	0.0	1.037	7UBAY_T1L1	BLCI111
MF3MBOHBOH104	2	304.5	294.5	10.0	0.0	0.0	1.033	7UBAY_T1L1	BOHECO1
MF3MGARPMSC01	2	59.5	58.1	1.4	0.0	0.0	1.024	7UBAY_T1L1	PMSC_BO
MF3MUBABOH201	2	1523.2	1481.2	36.9	4.1	1.0	1.028	7UBAY_T1L1	BOHECO2
MF3MUBABOH205	2	1270.5	1250.7	19.8	0.0	0.0	1.016	7UBAY_T1L1	BOHECO2
MF3MUBAMARC01	2	875.0	870.9	4.1	0.0	0.0	1.005	7UBAY_T1L1	MARCELA
MF3MBOHBLCI03	3	5460.0	5271.0	189.0	0.0	0.0	1.035	7UBAY_T1L1	BLCI111
MF3MBOHBOH104	3	273.0	264.5	8.5	0.0	0.0	1.031	7UBAY_T1L1	BOHECO1
MF3MGARPMSC01	3	63.0	61.6	1.4	0.0	0.0	1.023	7UBAY_T1L1	PMSC_BO
MF3MUBABOH201	3	1366.4	1330.3	31.2	4.1	0.8	1.026	7UBAY_T1L1	BOHECO2
MF3MUBABOH205	3	1212.8	1195.0	17.8	0.0	0.0	1.015	7UBAY_T1L1	BOHECO2
MF3MUBAMARC01	3	899.5	895.5	4.0	0.0	0.0	1.004	7UBAY_T1L1	MARCELA
MF3MBOHBLCI03	4	5194.0	5022.1	171.9	0.0	0.0	1.033	7UBAY_T1L1	BLCI111
MF3MBOHBOH104	4	252.0	244.5	7.5	0.0	0.0	1.030	7UBAY_T1L1	BOHECO1
MF3MGARPMSC01	4	66.5	65.0	1.5	0.0	0.0	1.022	7UBAY_T1L1	PMSC_BO
MF3MUBABOH201	4	1394.4	1358.9	30.6	4.1	0.9	1.025	7UBAY_T1L1	BOHECO2

Meter ID	HOUR	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MUBABOH205	4	1186.5	1169.8	16.7	0.0	0.0	1.014	7UBAY_T1L1	BOHECO2
MF3MUBAMARC01	4	791.0	787.6	3.4	0.0	0.0	1.004	7UBAY_T1L1	MARCELA

This finding affects all monthly SSLA results pertaining to any of the meters listed in the above table.
PEMC's BSMD investigated this problem and determined that:

1. Observed inconsistencies were all the results of incorrect SSLF as opposed to incorrect adjusted loads;
2. Incorrect SSLF were the results of erroneous equations accidently entered in some SSLA Excel template files; and

No loss computations, load loss adjustments, or settlement calculations were affected by these erroneous equations (as SSLF are in fact not used to adjust customer's raw measured loads).

Appendix 7: Spurious Loss Adjustments

Table 20: Monthly SSLA Output Data for MF3MBLKMECO01 on November 5, 2011

Meter ID	HOUR	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MBLKMECO01	1	-32,120.9	-32,093.1	-0.1	0.0	-27.7	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	2	-32,973.7	-32,948.7	-0.1	0.0	-25.0	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	3	-32,120.9	-32,097.4	-0.1	0.0	-23.5	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	4	-27,004.3	-26,985.5	0.0	0.0	-18.8	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	5	-25,583.0	-25,565.5	0.0	0.0	-17.5	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	6	-27,572.8	-27,553.4	0.0	0.0	-19.4	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	7	-26,151.6	-26,131.9	0.0	0.0	-19.7	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	8	-22,456.2	-22,437.1	0.0	0.0	-19.1	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	9	-13,075.8	-13,063.0	0.0	0.0	-12.8	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	10	0.0	0.000077926	-0.000078010	0.0	0.000000084	-342,723,443.724	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	11	1,137.0	1,135.5	0.0	0.2	1.3	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	12	2,842.6	2,838.7	0.0	0.4	3.4	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	13	-1,989.8	-1,987.5	0.0	0.0	-2.3	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	14	-3,126.8	-3,123.2	0.0	0.0	-3.6	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	15	-6,537.9	-6,530.6	0.0	0.0	-7.2	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	16	-5,400.9	-5,394.9	0.0	0.0	-6.0	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	17	-3,695.3	-3,691.3	0.0	0.0	-4.0	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	18	-2,558.3	-2,555.5	0.0	0.0	-2.8	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	19	-12,791.5	-12,777.5	0.0	0.0	-14.0	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	20	-17,055.4	-17,037.3	0.0	0.0	-18.1	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	21	-17,339.6	-17,321.8	0.0	0.0	-17.8	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	22	-15,918.3	-15,903.0	0.0	0.0	-15.4	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	23	-14,497.1	-14,483.6	0.0	0.0	-13.4	0.999	2BALNT_T1L1	MERALCO
MF3MBLKMECO01	24	-22,172.0	-22,151.8	0.0	0.0	-20.1	0.999	2BALNT_T1L1	MERALCO

Appendix 8: Large Line Losses in SSLA Data

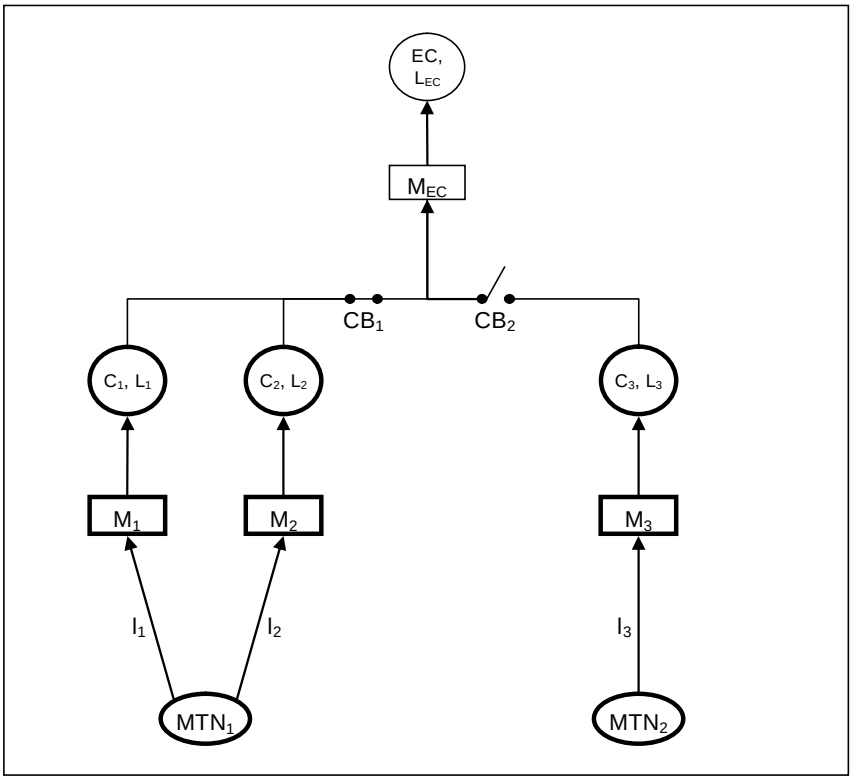
Table 21: Large Losses Observed on November 20, 2011

Meter ID	HOUR	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MCLNMECO01	1	23232.0	12459.1	10700.9	65.0	7.0	0.536	3CALAU_T1L1	MERALCO
MF3MCLNMECO01	2	0.0	0.0	10556.2	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO01	3	0.0	0.0	10583.0	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO01	4	0.0	0.0	10409.7	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO01	5	0.0	0.0	10475.1	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO01	6	3840.0	-6897.3	10672.1	65.0	0.2	-1.796	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	1	21888.0	11735.2	10081.8	65.0	6.0	0.536	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	2	0.0	0.0	10556.2	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	3	0.0	0.0	10583.0	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	4	0.0	0.0	10409.7	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	5	0.0	0.0	10475.1	0.0	0.0	1.000	3CALAU_T1L1	MERALCO
MF3MCLNMECO02	6	3600.0	-6470.2	10005.1	65.0	0.2	-1.797	3CALAU_T1L1	MERALCO

PEMC's BSMD investigated the problem and discovered that it was the result of a change in the switching configuration in this part of the network that they had not been notified about.

To understand this, let us consider the simplified representation of the set up given on the figure below.

Figure 29: Schematic Representation of the Standard Switching Configuration



We can see on Table 21 that customers MF3MCLNMECO01 and MF3MCLNMECO02 are connected to the same market trading node (3CALAU_T1L1). On Figure 29, C1 and C2 represent these two customers. They are connected to market trading node MTN1 and their loads and metering points are L_1 and L_2, and M_1 and M_2 respectively.

C_3 represents a third customer nearby but connected to another market trading node (MTN_2). C_3's load and metering point are noted L_3 and M_3 on Figure 29.

EC is an embedded customer that can source its power either from C_1 and C_2 or from C_3 depending on the switching configuration determined by circuit breakers CB_1 and CB_2. EC's load and metering points are noted L_{EC} and M_{EC}.

The situation described on Figure 29 corresponds to the standard (i.e. most common) switching configuration where EC sources its power from C_1 and C_2 (circuit breakers CB_1 and CB_2 are respectively: closed and open).

In this situation, the load measured at meter M_1 is customer C_1's load plus the fraction of EC's load that comes from C_1:

$$QM_1 = L_1 + L_{EC,1} \quad (1)$$

Note that QM_1 corresponds to the quantity noted "*Raw Value (kWh)*" on Table 21 for customer MF3MCLNMECO01. From (1), customer C1's load is expressed as follows:

$$L_1 = QM_1 - L_{EC,1} \quad (2)$$

Then to account for line and transformer losses occurring between C1 and market node MTN1 (noted l1 on the figure), C1's load must be adjusted as follows:

$$AL_1 = QM_1 - L_{EC,1} + l_1 \quad (3)$$

Treating the embedded customer's load as a component of losses in the data (i.e. having $Total\_Losses_1 = L_{EC,1} - l_1$), BSMD can compute customer C_1's adjusted load taking into account EC's embedded load with the following standard adjustment relation:

$$AL_1 = QM_1 - Total\_Losses \quad (4)$$

Similarly, for customer C_2, we have the following relations:

$$QM_2 = L_2 + L_{EC,2} \quad (5)$$
$$L_2 = QM_2 - L_{EC,2} \quad (6)$$
$$AL_2 = QM_2 - L_{EC,2} + l_2 \quad (7)$$

And C_2's adjusted load is computed as:

$$AL_2 = QM_2 - Total\_Losses_2 \quad (8)$$

Where $Total\_Losses_2 = L_{EC,2} - l_2$) and $L_{EC,2}$, which is the fraction of EC's load that comes from C_2, is treated as a component of the line and transformer losses that occur between MTN_1 and C_2.

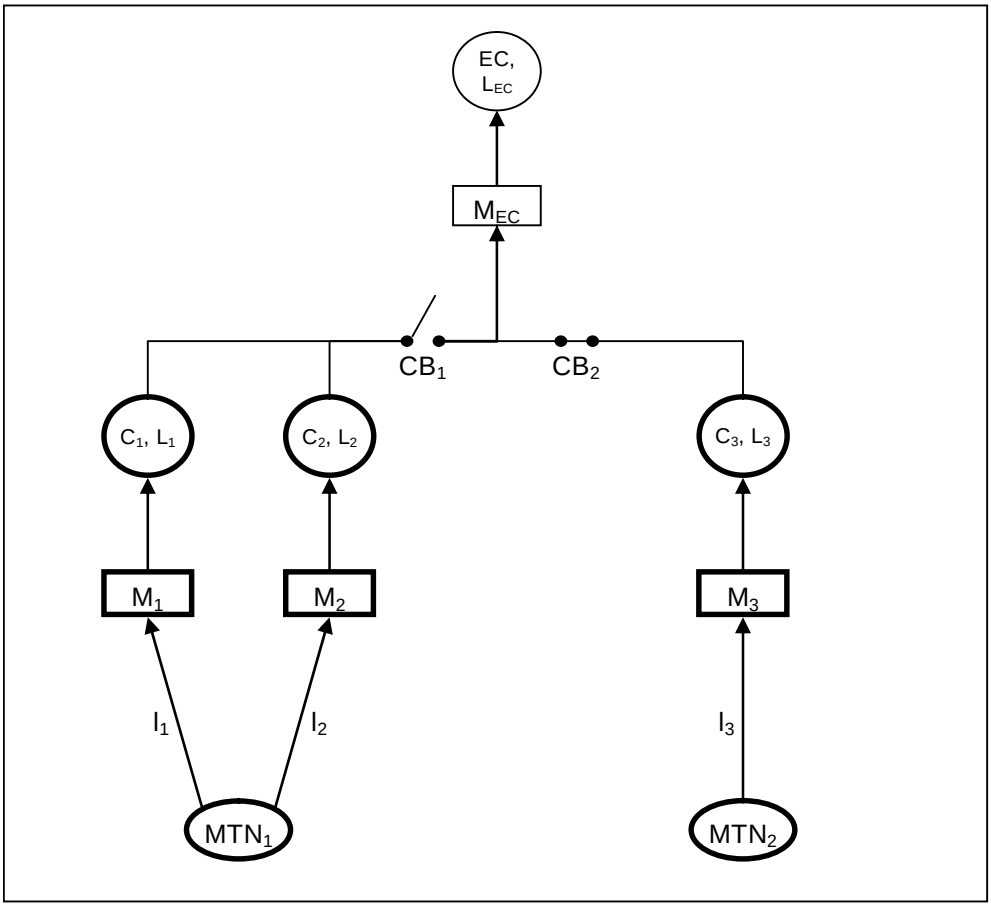
Note that BSMD's implementation is to add EC's load components ($L_{EC,1}$ and $L_{EC,2}$) to the data field noted "*Line losses (kWh)*" in table 23. This explains why sometimes, line losses seem large compared to MF3MCLNMECO01's and MF3MCLNMECO02's raw value loads. However, in the standard situation where the embedded customer is sourcing its power from MF3MCLNMECO01 and MF3MCLNMECO02 equations (1), (3), (5), and (7) above hold and therefore we have:

$AL_1 = L_1 + l1$ and
$AL_2 = L_2 + l2$

Consequently, adjusted loads for MF3MCLNMECO01 and MF3MCLNMECO02 should always be positive.

The data presented on Table 21 shows that this is not the case at hour 6. BSMD's investigations revealed that at this time period, the switching configuration was not the standard one but the one illustrated on the following simplified figure.

Figure 30: Schematic Representation of the Unusual Switching Configuration



In this configuration, circuit breakers CB_1 and CB_2 are now respectively open and closed and embedded customer EC is sourcing its power from host customer C_3.

When PEMC's BSMD is not aware that this is the current switching configuration, EC's load is still treated in the data as negative components of line losses associated with customers MF3MCLNMECO01 and MF3MCLNMECO02 (C_1 and C_2) and removed from their loads during the loss adjustment computations (with relations (4) and (8)).

The problem however is that since EC's load is not actually being sourced from C_1 and C_2, it is not recorded in the data as components of C_1's and C_2's raw load measurements (i.e. equations (1) and (5) do not hold). Instead, it is recorded (as it should be) as part of new host customer C_3's raw load measurement ($QM_3 = L_3 + L_{EC}$).

In conclusion, when the switching configuration is the one depicted on Figure 30, embedded customer EC sources its power from host customer C_3 and its load is correctly recorded as part of C_3's raw load measurement but it is not removed from C_3's load during the loss adjustment computations. On the other hand, even though EC's load is not recorded as part of C_1's or C_2's raw load measurements its load is removed from C_1's and C_2's loads during the loss adjustment computations.

Appendix 9: Large Negative Losses in SSLA Data

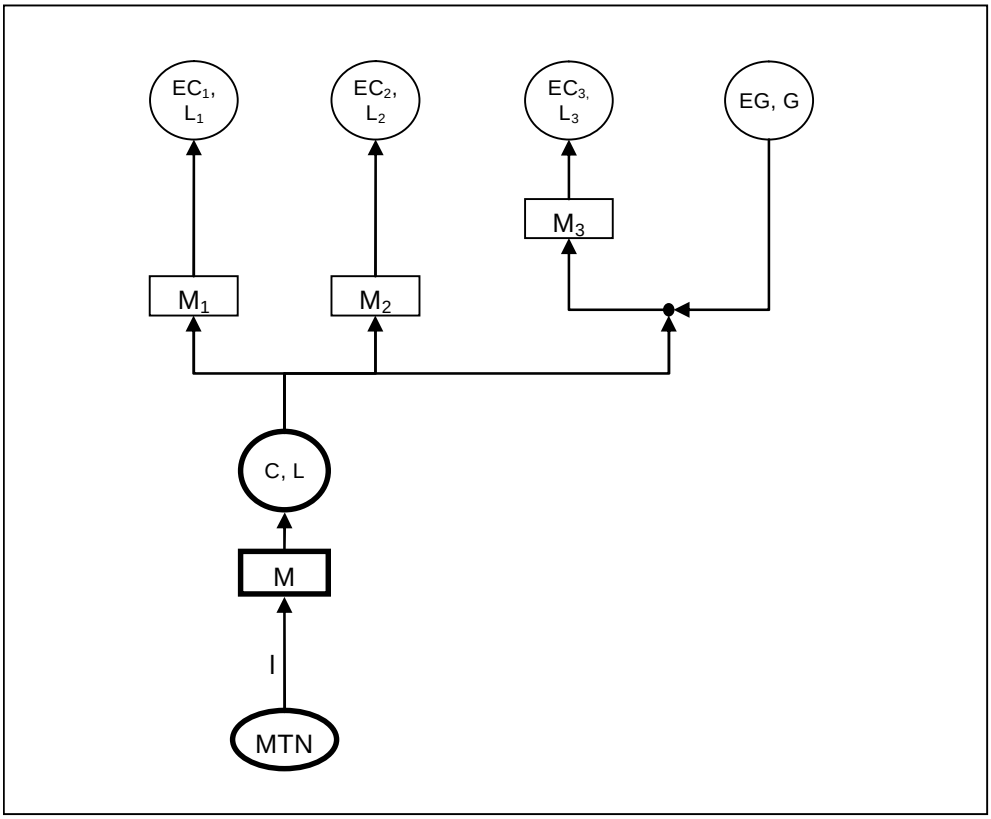
Table 22: Negative Losses Observed for MF3MITOBENE08

Meter ID	Date	Hour	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MITOBENE08	06-26-2011	1	979.2	-290.9	-1264.5	-5.3	-0.2	-0.297	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-26-2011	2	842.4	-427.1	-1261.0	-8.3	-0.3	-0.507	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-26-2011	3	612.0	-577.9	-1176.5	-13.0	-0.4	-0.944	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-26-2011	4	676.8	-542.2	-1207.2	-11.4	-0.4	-0.801	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-26-2011	24	1101.6	-107.9	-1207.6	-1.8	-0.1	-0.098	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-27-2011	1	979.2	-290.9	-1264.5	-5.3	-0.2	-0.297	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-27-2011	2	842.4	-427.1	-1261.0	-8.3	-0.3	-0.507	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-27-2011	3	612.0	-577.9	-1176.5	-13.0	-0.4	-0.944	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-27-2011	4	676.8	-542.2	-1207.2	-11.4	-0.4	-0.801	1LATRI_T2L2	1LTT2L2
MF3MITOBENE08	06-27-2011	24	1101.6	-107.9	-1207.6	-1.8	-0.1	-0.098	1LATRI_T2L2	1LTT2L2

PEMC's BSMD investigated the problem and determined that these large negatives losses were the result of a complex SSLA model involving three embedded customers (ITONIAA01, ITONPCZ01, ITOPMCZ02) and one embedded generator (ITOHEDC04) hosted by customer MF3MITOBENE08.

To understand this configuration, let us consider the simplified representation of the Market Trading Node of interest (1LATRI_T2L2) given on the figure below.

Figure 31: Schematic Representation of Market Trading Node 1LATRI_T2L2



Customer MF3MITOBENE08 (C on Figure 31), has three embedded customers (ITONIAA01 noted EC_1, ITONPCZ01 noted EC_2, and ITOPMCZ02 noted EC_3) and an embedded generator (ITOHEDC04 noted EG). C's load and meter are noted L and M and EC_1's, EC_2's, and EC_3's loads and meters are noted L_1, L_2, L_3 and M_1, M_2, M_3 respectively. EG's generation directly supplied to embedded customer EC_3 is noted G but EG has no meter, or at least no metering data that is made available to PEMC.

Under this setup, raw load measurements at meter M account for

- Customer C's load,
- The loads of embedded customers EC_1, EC_2, and EC_3, and
- The generation from embedded generator EG directly supplied to EC_3.

Therefore we have:

$$QM = L + L_1 + L_2 + L_3 - G \quad (1)$$

So customer C's load can be expressed as follows:

$$L = QM - L - L_1 - L_2 - L_3 + G \quad (2)$$

Then to account for line and transformer losses l occurring between customer C and its market trading node MTN, C's loss adjusted load is expressed as:

$$AL = QM - L_1 - L_2 - L_3 + G + l \quad (3)$$

Similarly to the situation described in our previous observation, BSMD should be able to compute the loss adjustments of customer C's load with a standard adjustment equation (AL = QM + Total_Losses) by treating the loads of the three embedded customers and the embedded generator in the data as components of the losses associated with customer C:

$$Total\_Losses = l - L_1 - L_2 - L_3 + G \quad (4)$$

However, the problem experienced here is that the generation from generator EG that is directly supplied to customer EC_3 cannot be measured so in actual fact, G is not included in the loss adjustment of customer C's load. In other words, the following relations are used to adjust C's load instead of (3) and (4):

$$AL = QM - L_1 - L_2 - L_3 + l \quad (5)$$
$$Total\_Losses = l - L_1 - L_2 - L_3 \quad (6)$$

This of course is incorrect any time EG is supplying power to EC_3 and explains how losses associated with the host customer (MF3MITOBENE08) can go negative in the data.

Appendix 10: Large Negative Line Losses in SSLA Data

Table 23: Large Negative Losses Observed for MF3MROSCEPZ03

Meter ID	Date	Hour	Raw Value (kWh)	Adjusted Value (kWh)	Line Losses (kWh)	Core Loss (kWh)	Copper Loss (kWh)	SSLF	MTN	Trading Part.
MF3MROSCEPZ03	11-19-2011	14	21.0	-672.4	-734.0	40.6	0.0	-32.020	3DASMA_T1L9	CEPZSEM

PEMC's BSMD investigated the problem and determined that it was due to incorrect data related to MF3MROSCEPZ03's load being provided to them.

BSMD explained that customer MF3MROSCEPZ03 sources some of its power directly from various local suppliers rather than from the grid. The fraction of MF3MROSCEPZ03's load that is supplied locally must be netted out of MF3MROSCEPZ03's raw measured load before settlement. To do this, each local supplier provides PEMC with measurements of the power it supplies to MF3MROSCEPZ03 and these measurements are used by PEMC's BSMD as negative components of the line losses in the loss adjustments model for customer MF3MROSCEPZ03.

In other words, the "*Line losses (kWH)*" field on table 23 above is really the amount of transmission loss that occur between market trading node 3DASMA_T1L9 and customer MF3MROSCEPZ03 minus the fraction of MF3MROSCEPZ03's load that is supplied by its local suppliers.

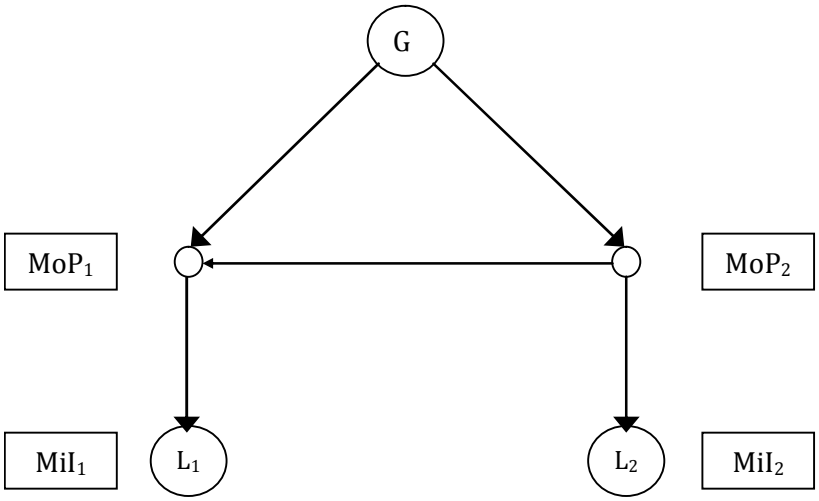
The problem observed at hour 14 on November 19, 2011, seem to have been caused by an error in the data provided by one of MF3MROSCEPZ03's local suppliers. According to BSMD's investigations, the value provided by local supplier ROSCEPZ05 for that period was clearly too large. This caused the "*Line Losses (kWh)*" value to be unusually low and resulted in MF3MROSCEPZ03's loss adjusted load to be negative.

Appendix 11: Market Network Model Analysis

When the monitoring point nearest to a particular metering installation is not represented by a MTN, then the SSLA procedure assigns this metering installation to another MTN for its adjustment calculations. With that, there might be cases that the resulting loss adjustment will not be a good representation of losses actually occurring on the path taken by energy flows between the metering installation and its true monitoring point.

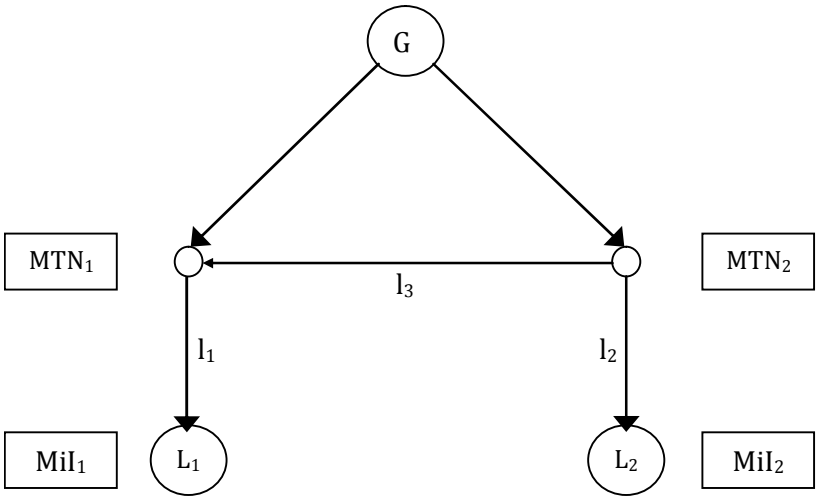
To illustrate this, let's take a look at the following simple example. Consider 2 loads (L_1 and L_2) connected to a source of generation (G) as on Figure 32 below.

Figure 32: Simple Example - Physical Energy Flows



Assume figure 32 is a schematic representation of the actual (physical) energy flows. Some of the energy from G goes to load L_1 via monitoring point MoP_1, the rest goes to monitoring point 2 (MoP_2) and then on to load L_2 except for a small fraction that goes to MoP_1 (assume the size of each arrow is an indication of the quantity of energy flowing). Loads at L_1 and L_2 are measured by metering installations MiI_1 and MiI_2 respectively.
If both monitoring points are represented by MTN in the MNM, we have the following situation.

Figure 33: Simple Example - Both Monitoring Points are Modelled



In this case, monitoring point MoP_1 is represented by MTN_1 and monitoring point MoP_2 is represented by MTN_2.

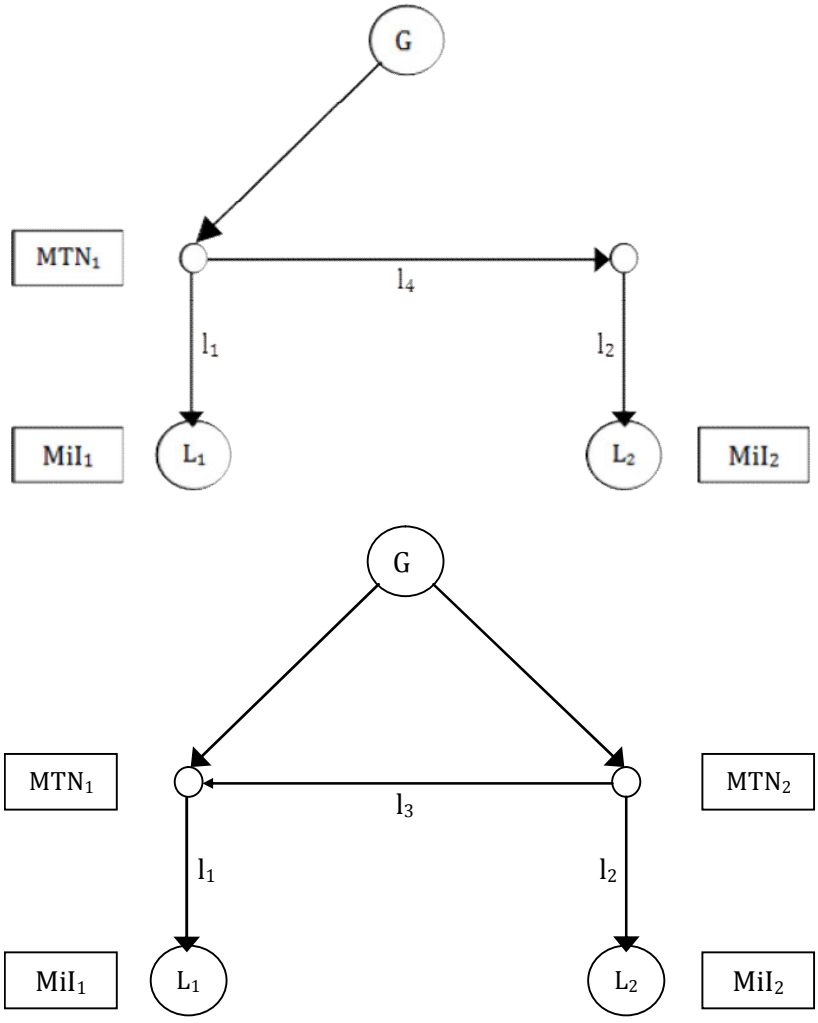
The loss adjustments calculated by the SSLA procedure are as follows:

$$Adj\_Qty(L_1,MTN_1) = MiI_1 + l_1$$
$$Adj\_Qty(L_2,MTN_2) = MiI_2 + l_2$$

These loss adjustments are consistent with actual energy flows (so is the dispatch calculated by MDOM).

Now if, for some reason, there is no MTN in the MNM to represent monitoring point MoP_2, we have the following situation.

Figure 34: Simple Example - MoP2 is not modelled



In this case the loss adjustments calculated by the SSLA procedure are as follows:

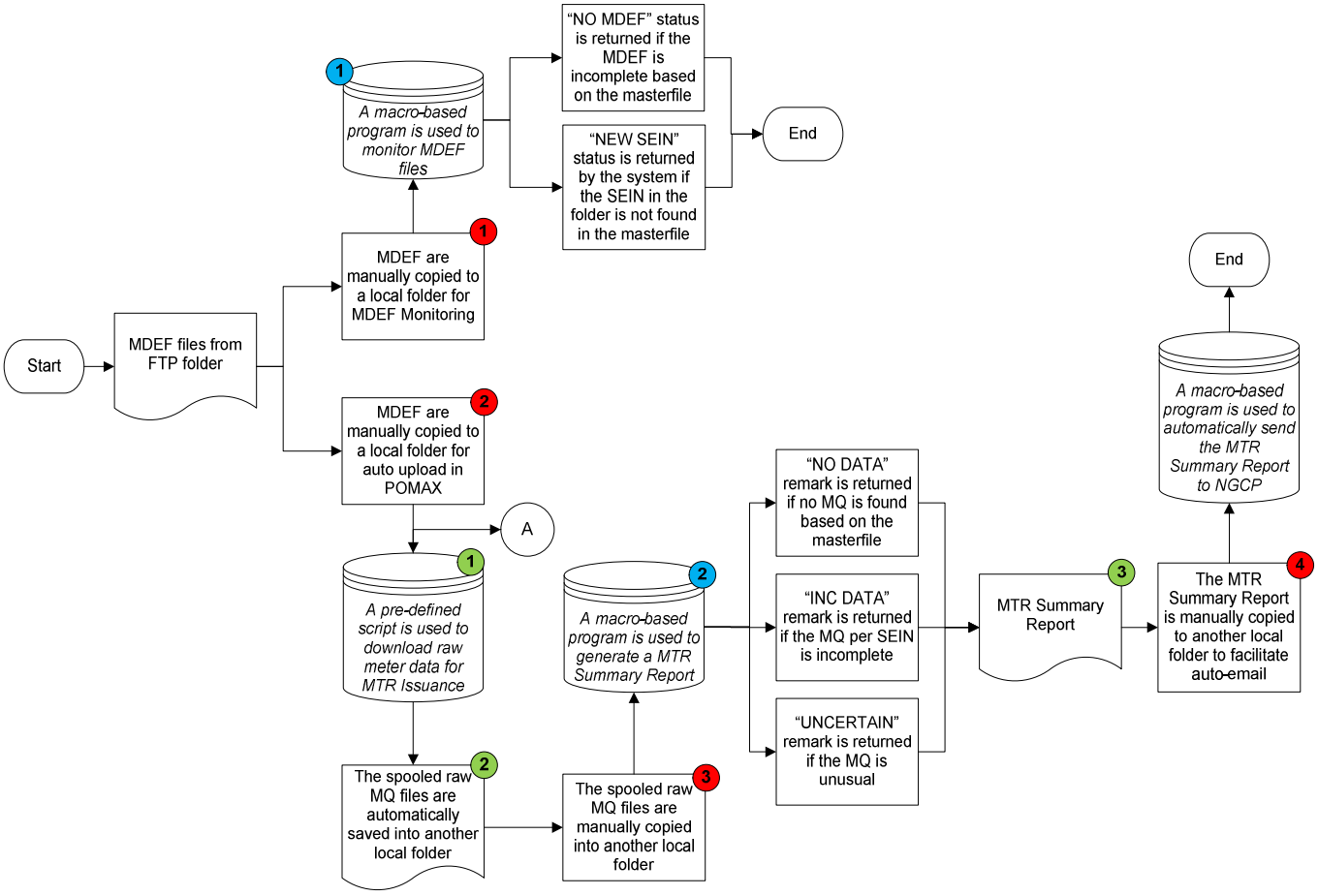
$$Adj\_Qty(L_1,MTN_1) = MiI_1 + l_1$$
$$Adj\_Qty(L_2,MTN_1) = MiI_2 + l_2 + l_3$$

We can see that, in this case, the dispatch given by MDOM and the loss adjustment for load L_2 are not consistent with actual energy flows. The essence of the problem is that there are flows in the meshed transmission network on the part between the distant MTN and the meter that are not properly accounted for in the SSLA calculation.

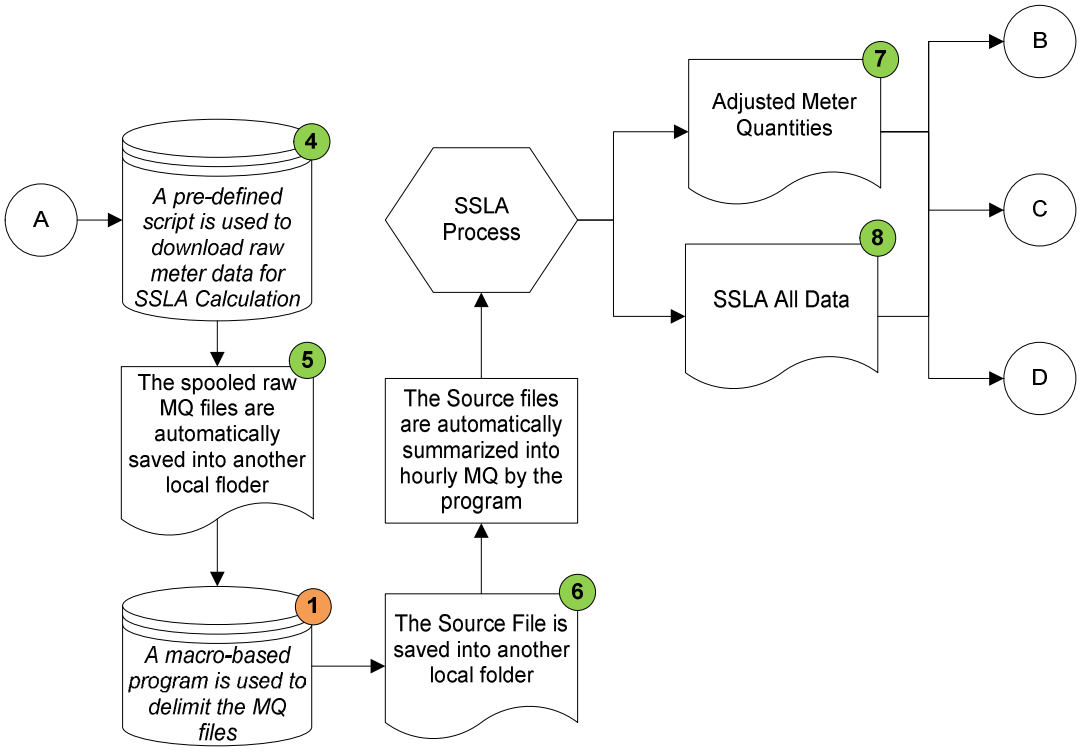
Appendix 12: Validation, Estimation and Editing Process Flow

Daily VEE Process

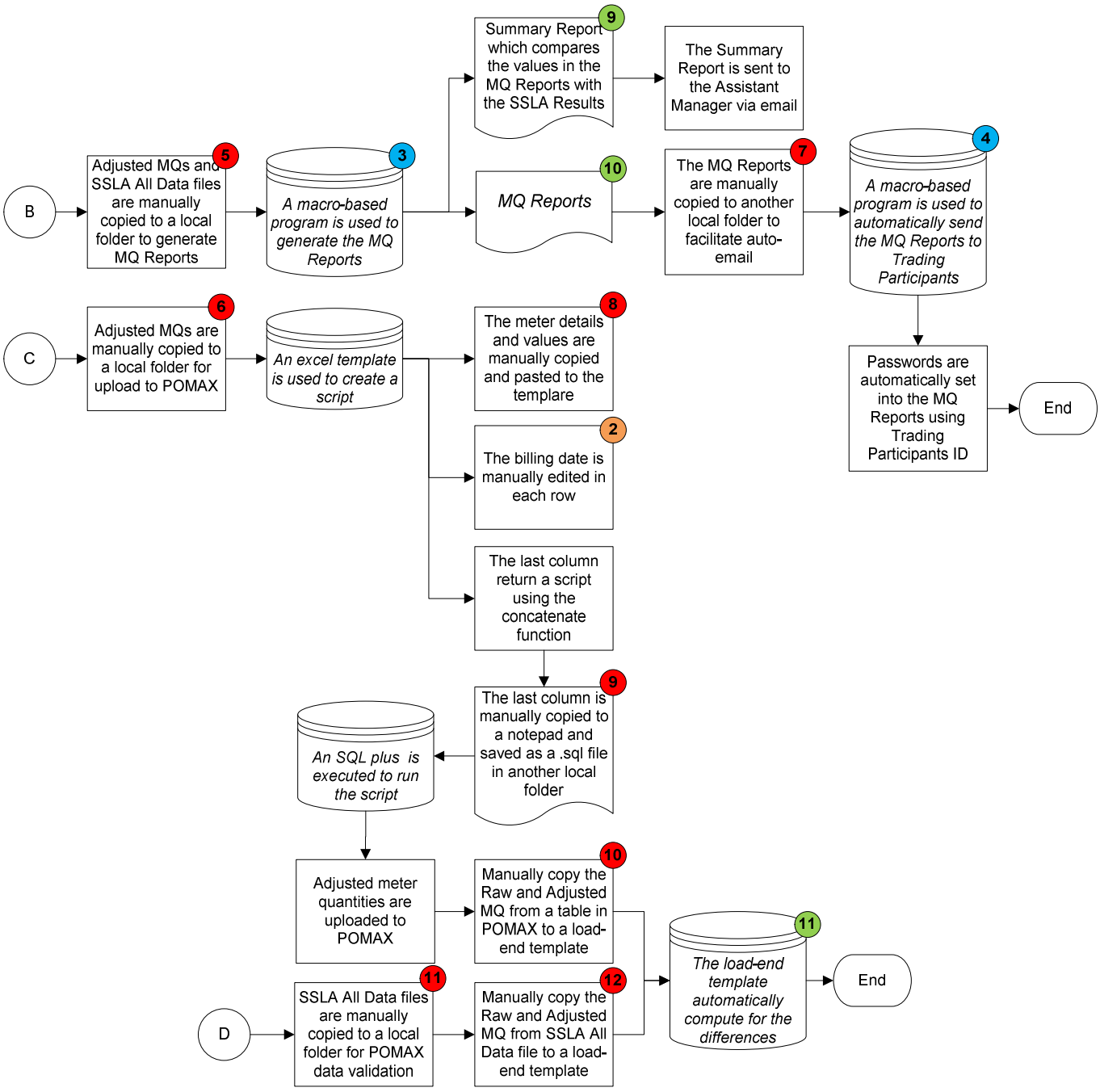
Uploading and Monitoring of MDEF Files and MTR Issuance



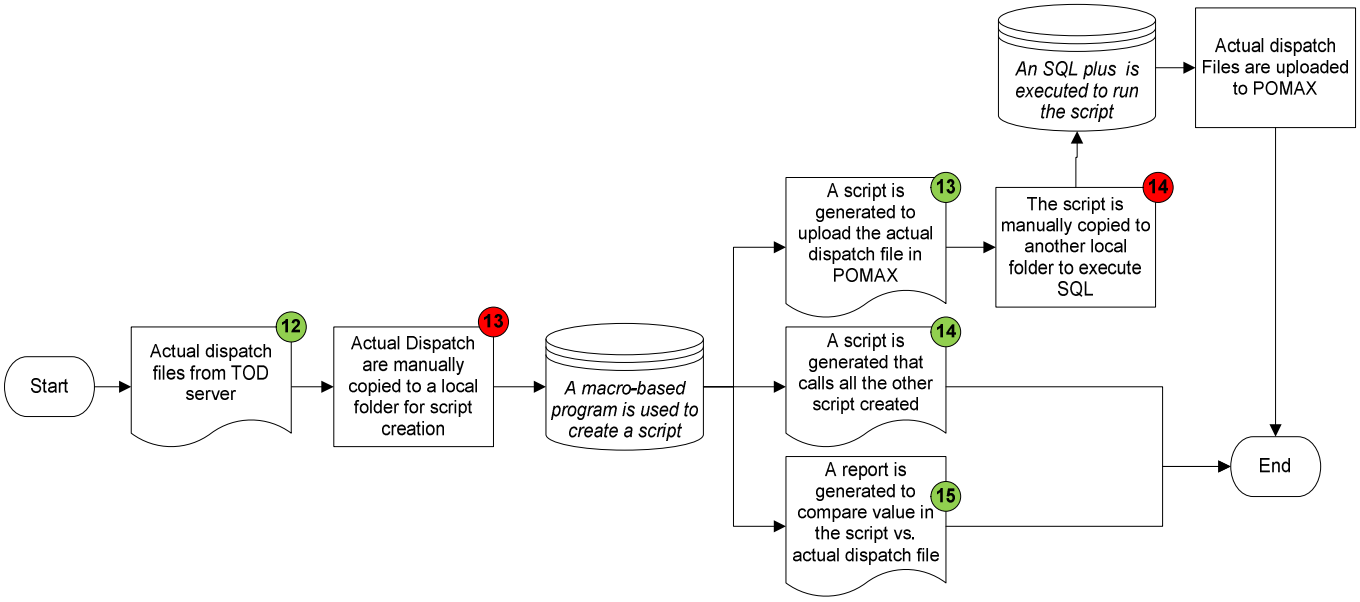
Daily Source File Generation for Use in SSLA Calculation



Generating and Sending MQ Reports to Trading Participants and Uploading of Adjusted Meter MQ in Meter Data Warehouse



Uploading Actual Dispatch to Meter Data Warehouse



Control Gap: Manual transfer of sensitive data files to different location
The manual copy-paste component of the whole BSMD process is prone to human error.

1. MDEF are manually copied to a local folder for MDEF Monitoring
2. MDEF are manually copied to a local folder for auto upload in POMAX
3. The spooled raw MQ files are manually copied into another local folder
4. The MTR Summary Report is manually copied to another local folder to facilitate auto-email
5. Adjusted MQs and SSLA All Data files are manually copied to a local folder to generate MQ Reports
6. Adjusted MQs are manually copied to a local folder for upload to POMAX
7. The MQ Reports are manually copied to another local folder to facilitate auto-email
8. The meter details and values are manually copied and pasted to the template
9. The last column is manually copied to a notepad and saved as a .sql file in another local folder
10. Raw and Adjusted MQ from a table in POMAX is manually copied to a load-end template
11. SSLA All Data files are manually copied to a local folder for POMAX data validation
12. Raw and Adjusted MQ from SSLA All Data file is manually copied to a load-end template
13. Actual Dispatch is manually copied to a local folder for script creation
14. The script is manually copied to another local folder to execute SQL

Control Gap: Unprotected input/output files
Most of the input files used and/or output files generated in the various processes of BSMD are editable and not appropriately protected giving windows to unauthorized party to manipulate the data and/or unintentionally change the information in the files.

1. A pre-defined script saved used to download raw meter data for MTR Issuance from POMAX.
2. Spooled raw MQ files which are the extracted meter data from POMAX that will be used as an input in MTR preparation.
3. MTR Summary Report

4. A pre-defined script used to download raw meter data for SSLA Calculation
5. Spooled raw MQ files which are the extracted meter data from POMAX that will be used as an input SSLA Calculation
6. The Source File that shows the extracted raw meter data from "csv" into MS Excel format on which the data would be delimited to create separate columns for the SEIN, year, week, day, hour, minute values for use in SSLA Calculation
7. Adjusted Meter Quantities – the generated file from SSLA Calculation
8. SSLA All Data – the generated file from SSLA Calculation
9. The Summary Report which compares the values in the MQ Reports with the SSLA Results
10. MQ Reports generated by the macro-based program
11. The load-end template which automatically computes for the differences the Raw and Adjusted values in POMAX and the one used in SSLA Calculation
12. Actual dispatch files from TOD server
13. The script generated to upload the actual dispatch file in POMAX
14. A script generated that calls all the other script created
15. The report is generated to compare value in the script vs. actual dispatch file

Control Gap: Manual input or copy-paste of meter data to different programs

Some of the processes require the user to input critical information and or manually copy-paste the data into the macro-based program and/or template. Inclusion of human intervention in the process poses higher risk than that of an automated one.

1. A macro-based program is used to delimit the MQ files. This program uses an ordinary delimit function in excel automated by the Macro-based program. Human errors can cause incorrect segregation of the data.
2. An excel template is used to create a script that would upload the Adjusted MQ in POMAX. The billing date is manually edited in each row in the script.

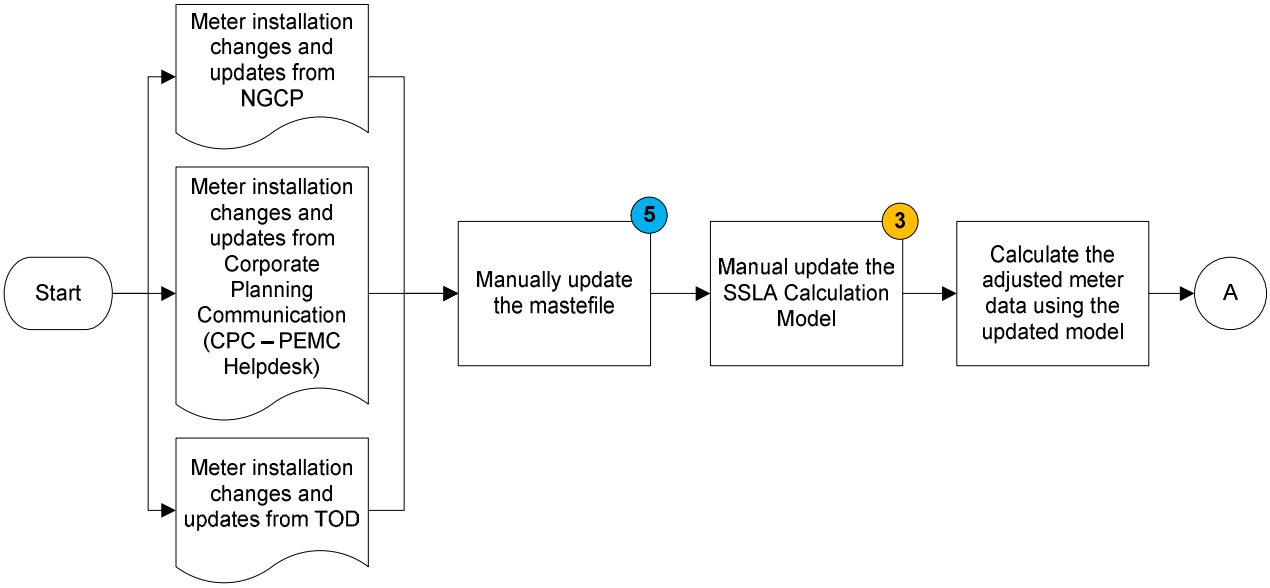
Control Gap: Manual updates of various masterfile

Masterfiles inside various macro-based programs use by BSMD are manually updated whenever there are new SEINs or changes to the existing SEINs need to be effected. Masterfile maintenance may not be properly implemented thus resulting to not synchronized master data in different locations.

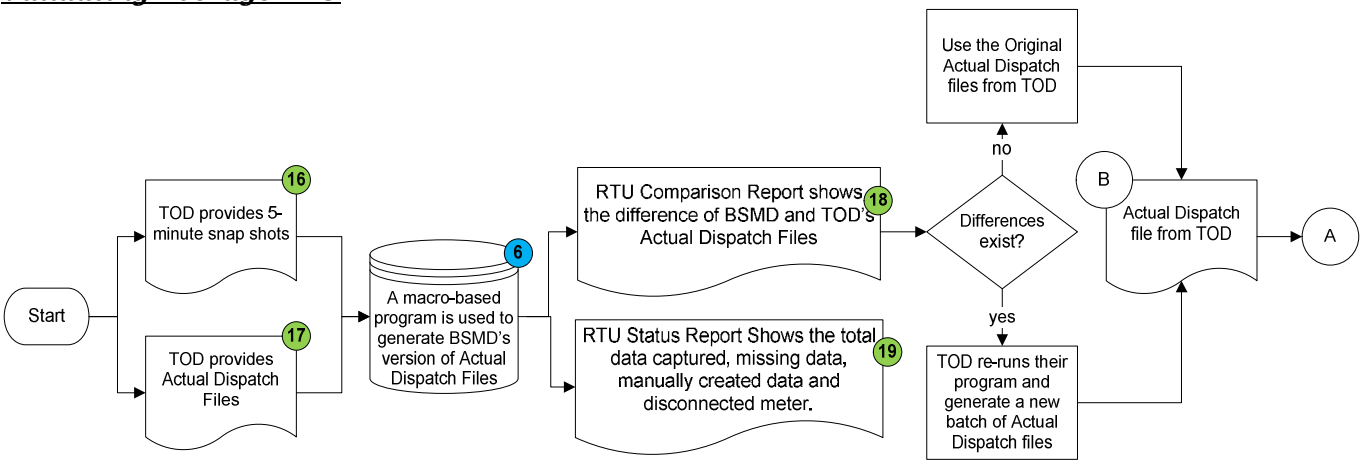
1. The masterfile in the macro-based program used to monitor MDEF files
2. The masterfile in the macro-based program used to generate a MTR Summary Report
3. The masterfile in the macro-based program used to generate the MQ Reports
4. The masterfile in the macro-based program used to automatically send the MQ Reports to Trading Participants

Monthly VEE Process

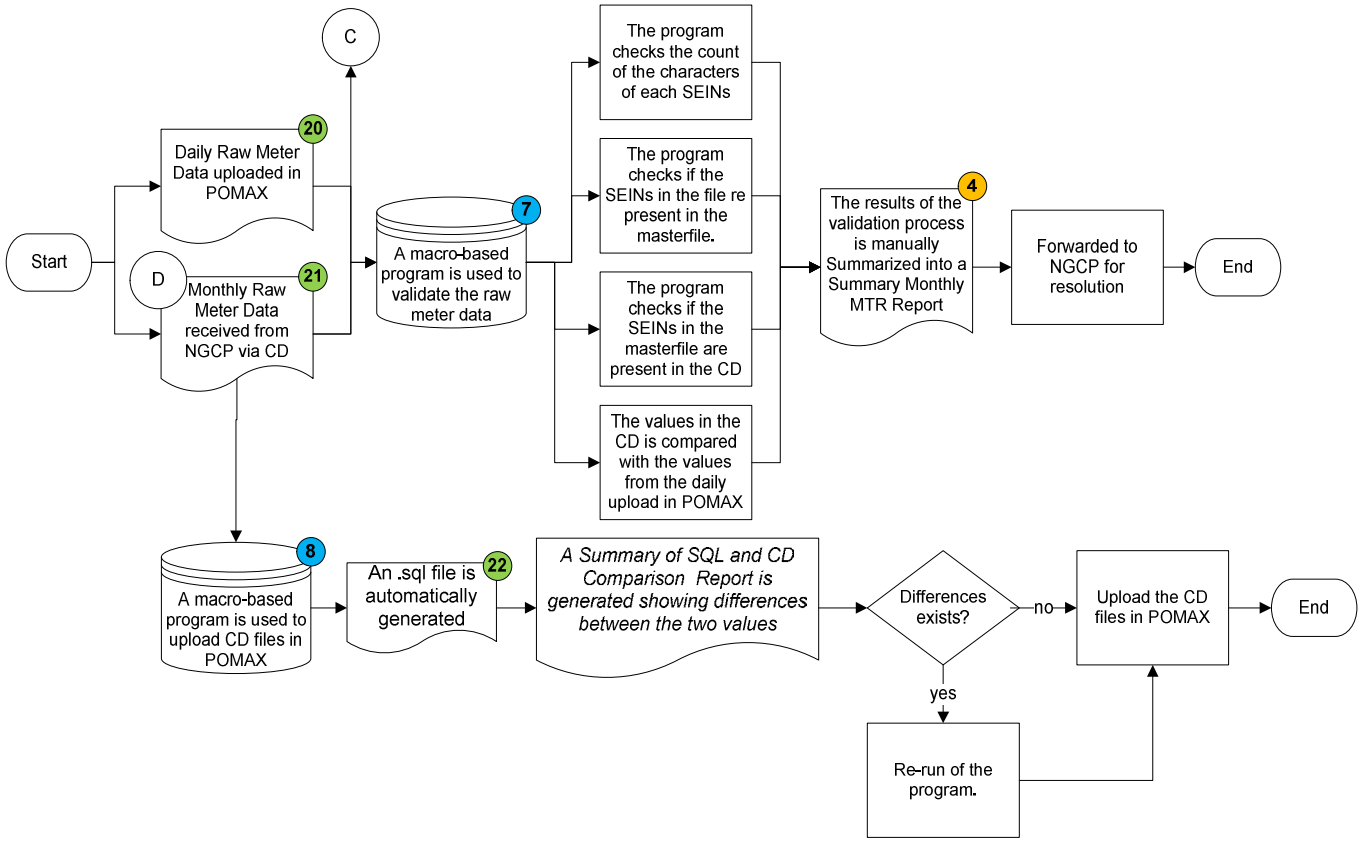
Monthly Updating of Master File



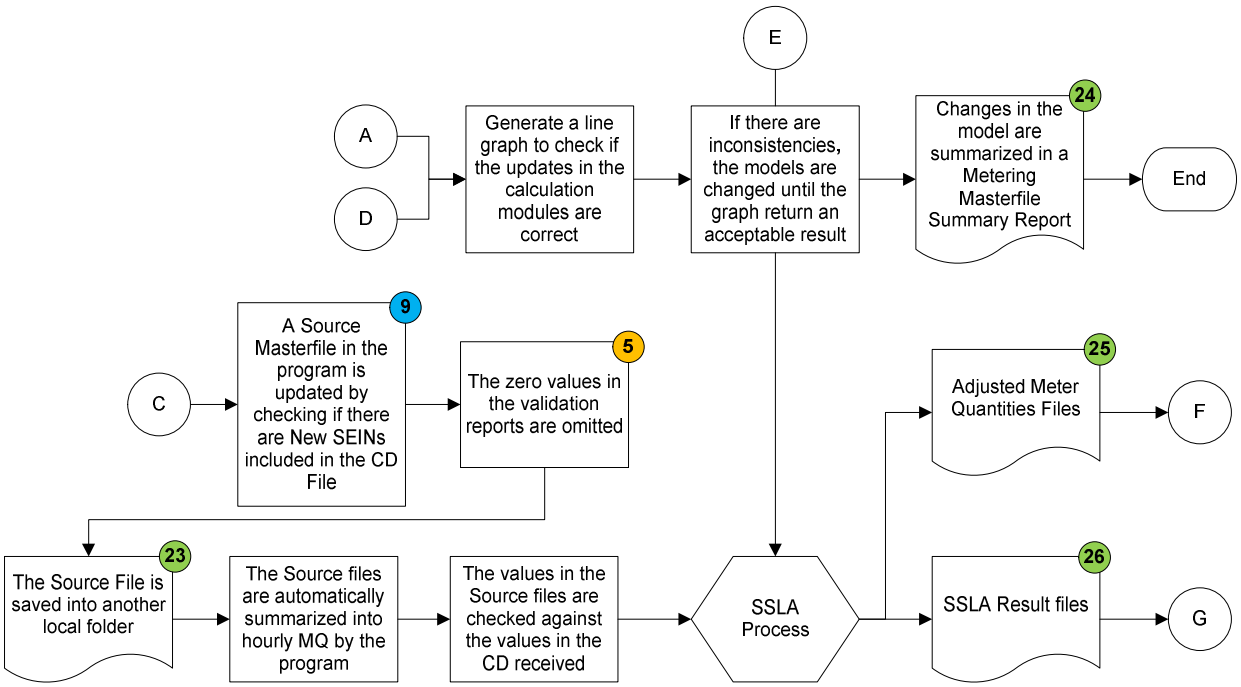
Validating Average RTU



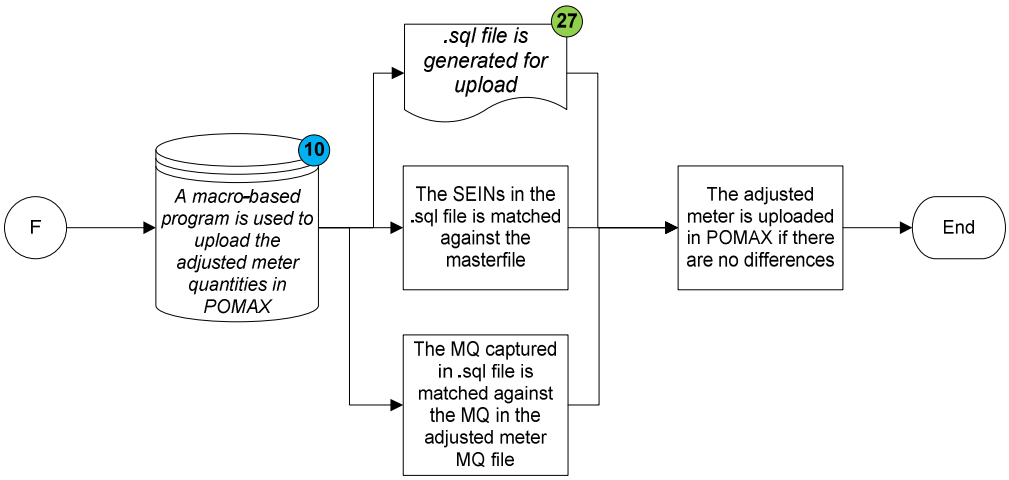
Meter Data and Issuance of MTR



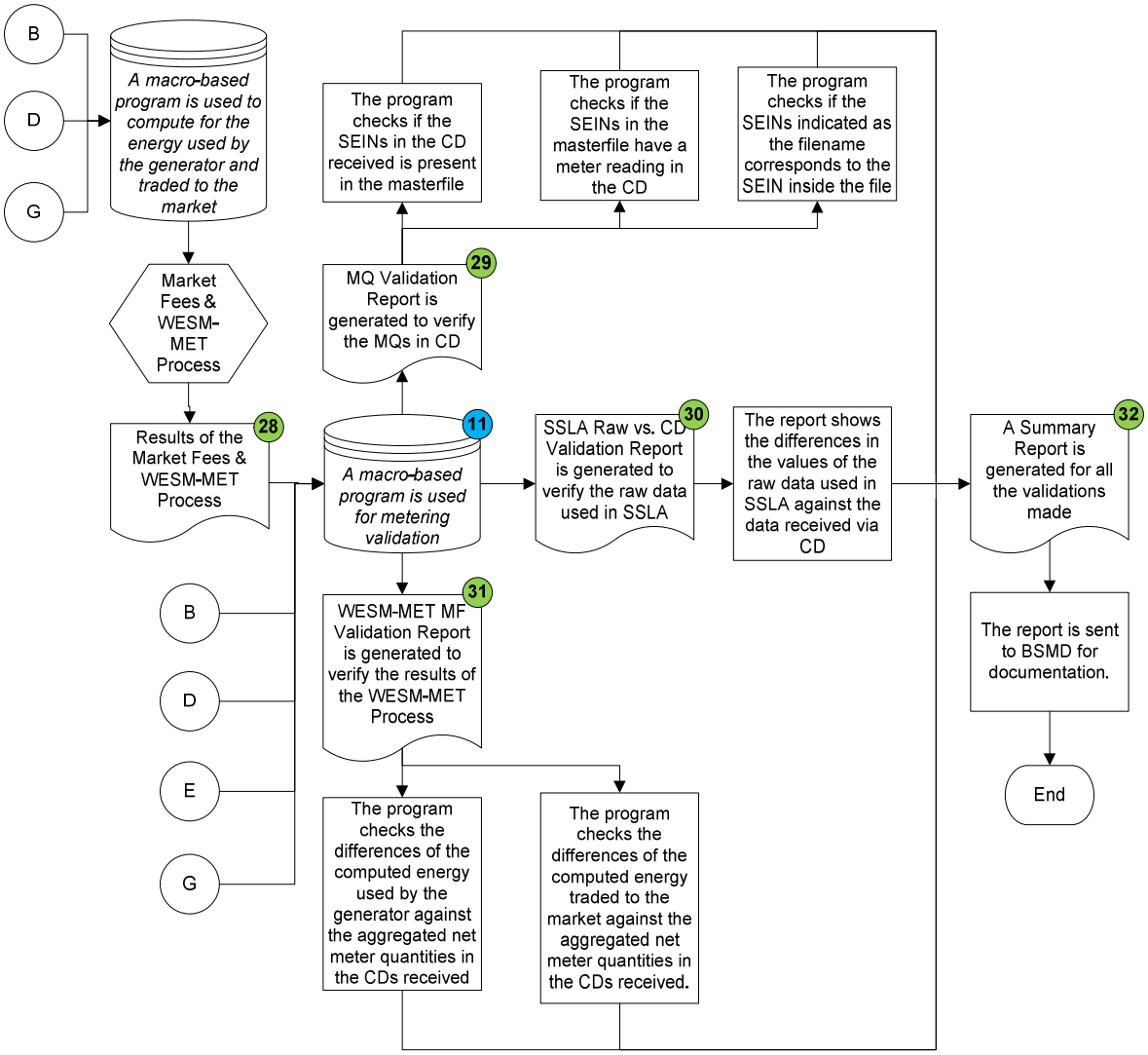
Monthly Running of Source Program to be used in SSLA Calculation



Adjusted Meter Quantities Conversion



Metering Validation



Control Gap: Unprotected input/output files

Most of the input files used and/or output files generated in the various processes of BSMD are editable and not appropriately protected giving windows to unauthorized party to manipulate the data and/or unintentionally change the information in the files.

16. 5-minute snap shots provided by TOPD
17. Actual Dispatch Files provided by TOPD
18. RTU Comparison Report that shows the difference of BSMD and TOD's Actual Dispatch Files
19. RTU Status Report that shows the total data captured, missing data, manually created data and disconnected meter
20. Daily Raw Meter Data file extracted from POMAX
21. Monthly Raw Meter Data received from NGCP via CD
22. An .sql file automatically generated used to upload the CD files to POMAX
23. The Source File used in SSLA Calculation
24. Metering Masterfile Summary Report

25. Adjusted Meter Quantities Files
26. SSLA Result files
27. An .sql file generated for upload used to upload the Adjusted MQ in POMAX
28. Results of the Market Fees & WESM-MET Process
29. MQ Validation Report generated to verify the MQs in CD
30. SSLA Raw vs. CD Validation Report generated to verify the raw data used in SSLA
31. WESM-MET MF Validation Report generated to verify the results of the WESM-MET Process
32. A Summary Report generated for all the validations made

Control Gap: Manual input or copy-paste of meter data to different programs

Some of the processes require the user to input critical information and or manually copy-paste the data into the macro-based program and/or template. Inclusion of human intervention in the process poses higher risk than that of an automated one.

3. Manual update of the SSLA Calculation Model
4. The results of the validation process is manually Summarized into a Summary Monthly MTR Report
5. The zero values in the validation reports are omitted in the Source Masterfile

Control Gap: Manual updates of various masterfile

Masterfiles inside various macro-based programs use by BSMD are manually updated whenever there are new SEINs or changes to the existing SEINs need to be effected. Masterfile maintenance may not be properly implemented thus resulting to not synchronized master data in different locations.

5. Manually the masterfile used in SSLA Calculation
6. Masterfile in the macro-based program used to generate BSMD's version of Actual Dispatch Files
7. Masterfile in the macro-based program used to validate the raw meter data
8. Masterfile in the macro-based program used to upload CD files in POMAX
9. A Source Masterfile in the macro-based program is updated by checking if there are New SEINs included in the CD File
10. Masterfile in the macro-based program used to upload the adjusted meter quantities in POMAX
11. Masterfile in the macro-based program used for metering validation

Appendix 13: Meter Integrity Test Results

1. Phasor Diagram

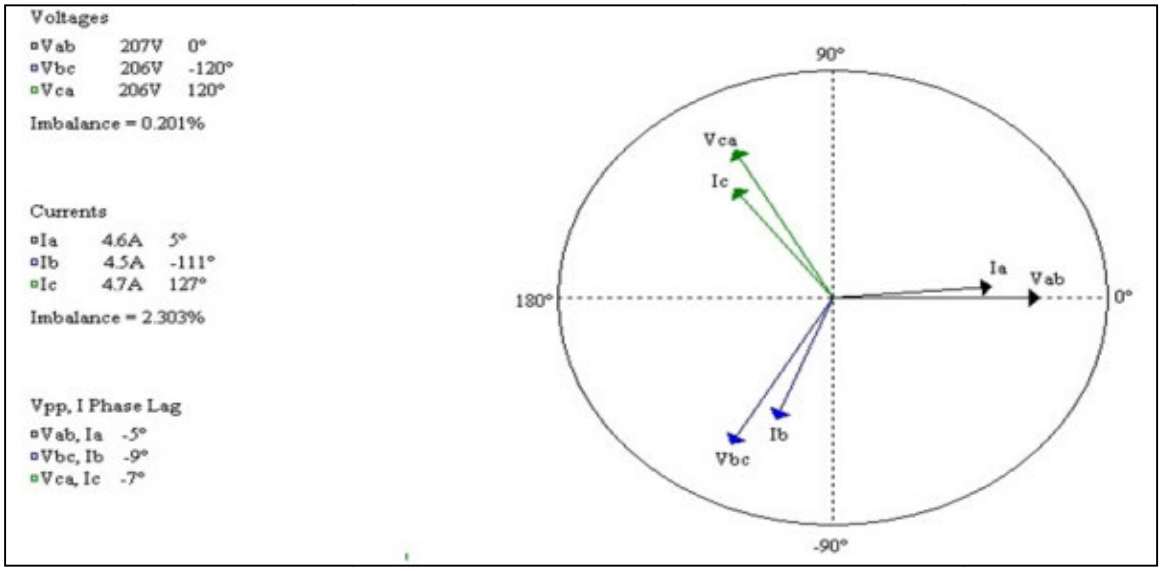
A phasor diagram is a graphical representation of two or more sinusoidal functions (sine wave). For electric meters, these may be either voltage, current or some other alternating quantity, all of the same frequency.

Phasors are drawn with their magnitude, angle of displacement and rotating in a counter clockwise direction, with a common point of origin. Phasors ahead of the reference phasor are said to be "**leading**" while those behind the reference phasor are said to be "**lagging**". **In a three-phase balanced system, each individual phasor is displaced by 120°.**

In a unidirectional flow (i.e. Direct Current or DC), the current and the voltage are exactly in phase. **In an oscillating flow (i.e. Alternating Current or AC) the current and voltage are exactly a quarter of a period out of phase, either the current is leading or the voltage is leading**. Leading or lagging depends on the type of the electrical resistance of the load: if it is inductive (i.e. coils etc.), the current will lag, if capacitive, the current will lead the voltage. In mixed flow, the phase is somewhere between zero and a quarter a period. Commonly, the 'out of phase' of either current or voltage is used as a measure for the 'quality' of the load.

In addition to determining the type of load, phasor diagrams are also useful in determining the power factor, load imbalance, meter connections (incorrect phase rotation), CT polarity, and other errors.

Figure **35: Phasor Diagram**



Current transformers (CTs) exhibit two primary errors:

a. Accuracy errors (related to gain or linearity)
b. Phase angle errors

Accuracy errors are fairly easy to understand. If a CT reads 0.5% low at 20 amps, then it would report 19.9 amps instead of 20 amps. Any measurements based on the current, such as power or energy, would similarly read low by 0.5%.

Phase angle errors are more complex. The current transformer introduces a phase shift (or time delay) in the AC current signal, relative to the actual current. This is commonly measured in degrees and varies from 0.2 degrees (or better) for highly accurate CTs to as high as 6 degrees. **At and near unity power factor, CT phase angle errors have little effect on the measured power and energy. However, at lower power factors, such as 0.7 or below (especially below 0.5), even small phase angle errors can cause large errors in the measured power and energy.**

1.1. CT Phase Angle Correction

Current transformers introduce a phase angle error between the current being measured and the voltage signal they generate. Most CTs have a leading phase angle error, where the voltage signal from the CT leads the actual current waveform by a small amount, typically 0.5° to 2.0° (larger for some models). This CT phase angle error results in an error in the reported power. **The error is negligible at unity power factor and increases as the power factor gets lower**.

1.2. Lagging Current - Motor or Inductor Load

In this case, the CT phase angle error (assuming it is greater than one degree) will make the power factor and real power values look higher than they actually are, especially for low power factors. The corrected values will show a lower power factor and lower real power. The energy will show the same error as the power, so if the power reads 2.5% high, then the energy reading will also be 2.5% high.

1.3. Leading Current - Capacitive Load

This occurs with power supplies or due to the filter capacitors on inverters. In this case, the CT phase angle error (assuming it is greater than one degree) will make the power factor and real power values look lower than they actually are, especially for low power factors. The corrected values will show a higher power factor and higher real power. The energy will show the same error as the power, so if the power reads 2.5% high, then the energy reading will also be 2.5% high.

INSPECTION RESULT: All meters tested showed normal phase angle deviations (e.g. Voltage phase A (V_A) = 0°, Voltage phase B (V_B) = 120° (0° + 120°), Voltage phase C (V_C) = 240° (240° + 120°).) No relevant exceptions noted.

2. Accuracy and Load Test

Meter accuracy, denoted in percentage, is defined by comparing the difference of energy consumption recorded by the "Meter Under Test" and of the "Reference Meter" with the energy consumption recorded by a reference meter. It is computed as follows:

$$Accuracy\ (\%) = [(E_{MUT} - E_{REF})]/\ E_{REF} \times 100\%\ (IEC62053\text{-}21)$$

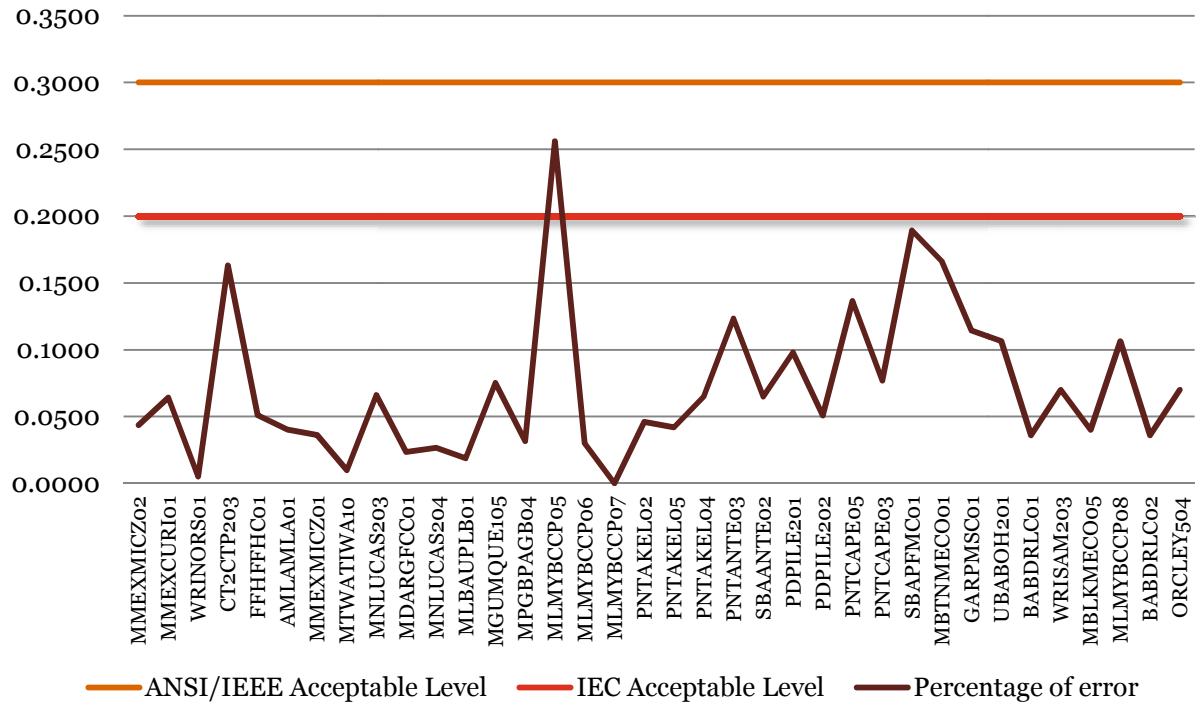
As required by **Sec. 2.4.1- Requirements for Grid Meters**, the **accuracy of the meter to be used shall be ±0.3%.** Since accuracy is affected by the load and the power factor (see previous discussion on CT accuracy), the test is conducted at combined variations of the two, as shown below:

a. Full Load (100%) at 100% Power Factor (PF=1.0)
b. Light-Load (10%) at 100% Power Factor (PF=1.0)
c. Full Load (100%) at 50% Power Factor (PF=0.5)

Note that for the entire test conditions stated above, the Meter Under Test (MUT) should register the required minimum accuracy of ±0.3% based on ANSI/IEEE Acceptable Value.

INSPECTION RESULTS: All of the meters tested passed the minimum accuracy requirement. No relevant exceptions noted.

Figure 36: Accuracy Test Result



Priority Sites Analysis

Table 24: Summary of Issues on Priority Sites

	Connection Point (SEIN)	Trading Participant	Communication Link	System Time vs. Meter Time	Revenue meter and enclosure issues (main and alternate)	Meter Seal Issues	Instrument Transformer Issues	Grounding Issues	Perimeter Security
1	MBLKMECO05	MANILA ELECTRIC COMPANY			x			x	
2	MMEXCURI01	CURIMAO ALUMINUM CORPORATION			x				
3	MMEXMICZ01	STRONGHOLD STEEL CORPORATION			x				
4	MMEXMICZ02	STRONGHOLD STEEL CORPORATION			x				
5	MLMYBCCP05	BATAAN COMBINED CYCLE POWER PL			x	x	x		
6	MLMYBCCP06	BATAAN COMBINED CYCLE POWER PL			x	x	x		
7	MLMYBCCP07	BATAAN COMBINED CYCLE POWER PL			x	x	x		
8	MLMYBCCP08	BATAAN COMBINED CYCLE POWER PL			x	x			
9	MBTNMECO01	MANILA ELECTRIC COMPANY			x	x	x	x	
10	MGUMQUE105	QUEZON I ELECTRIC COOPERATIVE INC.			x	x	x		x
11	MLBAUPLB01	UP LOS BAÑOS COLLEGE OF AGRICULTURE					x		
12	MPGBPAGB04	PAGBILAO COAL FIRED THERMAL POWER PLANT			x	x		x	
13	MNLUCAS203	CAMARINES SUR II ELECTRICT COOPERATIVE , INC		x	x		x		x
14	MNLUCAS204	CAMARINES SUR II ELECTRICT COOPERATIVE , INC			x		x		
15	MDARGFCC01	GOOD FOUND CEMENT CORPORATION	x		x				
16	MTWATIWA10	TIWI GEOTHERMAL POWER PLANT A			x		x		x
17	UBABOH201	BOHOL II ELECTRIC COOPERATIVE			x		x		
18	GARPMSC01	PHILIPPINE MINING SERVICE CORPORATION					x		x
19	BABDRLC01	DON ORESTES ROMUALDEZ ELECTRIC COOPERATIVE	x	x	x		x		x
20	BABDRLC02	DON ORESTES ROMUALDEZ ELECTRIC COOPERATIVE	x	x	x		x		
21	ORCLEY504	LEYTE V ELECTRIC COOPERATIVE, INC.	x			x			x
22	WRINORS01	NORTHERN SAMAR ELECTRIC COOPERATIVE, INC.		x	x		x		x
23	WRISAM203	SAMAR II ELECTRIC COOPERATIVE, INC.			x	x	x	x	
24	CT2CTP203	CEBU II THERMAL POWER PLANT							
25	PNTAKEL02	AKLAN ELECTRIC COOPERATIVE, INC.			x		x		x
26	PNTAKEL04	AKLAN ELECTRIC COOPERATIVE, INC.		x			x	x	x
27	PNTAKEL05	AKLAN ELECTRIC COOPERATIVE, INC.			x		x		x
28	PNTANTE03	ANTIQUE ELECTRIC COOPERATIVE, INC.	x				x		x
29	SBAANTE02	ANTIQUE ELECTRIC COOPERATIVE, INC.			x				
30	PNTCAPE03	CAPIZ ELECTRIC COOPERATIVE, INC.				x	x	x	x
31	PNTCAPE05	CAPIZ ELECTRIC COOPERATIVE, INC.					x		x
32	PDPILE201	ILOILO II ELECTRIC COOPERATIVE, INC.					x		x
33	PDPILE202	ILOILO II ELECTRIC COOPERATIVE, INC.	x		x	x	x		x
34	SBAPFMC01	PHILIPPINE FOREMOST MILLING CORPROATION					x		
35	FFHFFHC01	FORMER FARMER HOLDINGS CORP.			x	x	x		x
36	AMLAMLA01	ICS RENEWABLES				x		x	

Initially, there were 36 metering sites registered in the WESM, which were identified by the PAC and Metering Arrangement Review–Technical Working Group (TWG) as critical and most problematic and would require more comprehensive and rigid review.

These priority sites were covered during the physical site inspection. Summarized below are the results of that inspection conducted on these 36 priority sites:

a. Of the 36 critical and significant sites identified, **36 or 100%** use Global System for Mobile (GSM) as its communication link technology between the metering facility and the metering database (i.e. MV-90). It was noted that **5 out of 36 (13.89%)** GSM-dependent sites have intermittent to weak signal propagation (-90dBm and below) and **1 out of 36 (2.78%)** has no (0 dBm) signal propagation at all.

   Communication links that fall below the minimum acceptable signal strength of -90 dBm may result to failed or unsuccessful retrieval and transmission of meter data. It may be inferred that the troubles encountered by these sites with regard to remote data acquisition is brought about by the problem in signal propagation.

b. The metering database or MV-90 has the functionality to synchronize time differences of up to +/- five (5) minutes. The factors that affect asynchronous time include, among others, the type of communication link (e.g. the signal strength propagation for the facilities that use GSM). Taking into consideration the location of the metering facility and especially during night time where fading occurs, the signal strength may vary. In line with this, it was noted, that **1 out of 36 (2.78%)** sites has a time discrepancy of more than 5 minutes in the main meter and **4 out of 36 (11.11%)** have time discrepancies of more than five 5 minutes in the alternate meters.

   The major risk associated with the time discrepancies between the meter and the metering database system (MV-90) is the likelihood of retrieving inaccurate meter data in view of the fact that it does not capture the flow of electricity at an exact particular time. Since the meter installations capture the meter data cumulatively, these time discrepancies may result to recurring and successive errors until detected.

c. The revenue meters of the 36 priority sites, both main and alternate, as well as the meter enclosures were also inspected. The observation includes areas concerning inadequate and non-functional meter displays, time discrepancies between the metering database system and the meter, inadequate cabinet housings, inadequate ventilations, absence of viewing windows, enclosure security, absence of alternate meters and inadequate test switches.

   Out of the 36 sites identified, **25 or 69.44%** were noted to have issues on inadequacies on the revenue meters and the meter enclosures. Accordingly, these issues may generally affect the performance, functioning, efficiency or integrity of the metering operations as well as the security of the metering installations.

d. It was observed that **13 out of the 36 (36.11%)** critical and significant sites have issues on seal monitoring process and security seals attached to the revenue meters and the secondary terminal boxes of the instrument (potential and current) transformers. These inadequacies may pose risks to unauthorized access and possible changes or alterations to the revenue meters and instrument transformers.

e. The instrument transformers – potential, current and the lightning arresters - were also inspected. Out of the 36 critical and significant sites identified, **25 or 69.44%** were noted to have issues on instrument transformers. These include non-compliance with the requirements of the WESM-MSDM-007 Metering Standards and Procedures and other relevant electricity standards with regard to the technical specifications of the instrument transformers as well as observations on their physical condition, including the instrument terminals, instrument tank casings, wires and cabling, secondary conduits and the instrument mounting structures.

   Furthermore, it was also observed that there are Four (4) meters of Bataan Combined Cycle Power Plant utilizing a Bushing type Current Transformers.

Bohol II Electric Cooperative is using a double bushing Potential Transformer among the 36 priority sites.

Accordingly, these departures from the applicable standards and inadequacy of the preventive maintenance provided to the equipments expose the metering facilities to risks of affecting the accuracy of the metering information, efficiency of the metering operations and the safety and security of the metering installations.

f. It was also observed that **7 out of the 36 (19.44%)** critical and significant sites have high grounding issues. High grounding resistance installation exposes the metering facilities to surges or direct lightning hit. Furthermore, it exposes the metering facility to the dangers of electric shock under normal and faulty conditions.

g. The physical inspection also covered the perimeter security of the metering facilities, taking into account, among others, the perimeter protection type, access controls, surface grade types, adequacy of illumination and vegetation growth on the metering facilities. Out of the 36 critical and significant sites, **16 or 44.44%** were noted to have issues regarding the perimeter security of the metering facilities. Generally, these perimeter security issues may pose the risk of unauthorized access to the metering facility and its metering installations and equipments as well as other relevant safety and security issues that maybe encountered in the site.

In addition, all metering installation in the thirty six (36) priority sites was subjected to the meter accuracy and integrity test. All sites showed normal phase angle deviations, and passed the minimum accuracy requirement. No relevant exceptions were noted as of the time of the site visits.

Appendix 14: Mapping of Test Procedure and Audit Requirement

Table 25: Mapping of Test Procedure and Audit Requirement

Audit Objective (Per RFP)	Audit Procedures Performed	*Section Reference*
Best Practices in other competitive electricity markets	Based on our understanding of the metering operations in place and knowledge in other electricity markets, we presented specific practices acceptable, both locally and internationally, that could further improve specific operational areas in the MSP and MO, and WESM as a whole. We provided guidance on better practices in the following areas: a. Organizational structure b. Market Operator directorship c. Market rules and manuals d. Implementation of market rules e. SSLA Calculations f. Metering installations	Best Practices Section; and in specific Recommendations
Available technology and its cost	We understood the different technology currently used by both the MO and MSP for the whole metering process. We then identified areas for improvement relating to this area, and presented similar technologies used in other electricity markets.	Best Practices Section -Practical Implementation of Market Rules - Data Storage and Data Transmission Section 3: Market Operator Section 4: Metering Service Provider Section 5: Metering Installation
Timeliness of addressing Meter Trouble Reports (MTR)	We conducted interview and walkthrough on the MTR creation and resolution process both on the MSP and MO side. We identified the existence and assessed the effectiveness of different monitoring controls through the performance ratings in place to make sure that MTRs are addressed in a timely manner.	Section 3 Market Operator - Validation Estimation and Editing Process Review and Data Accuracy Testing - Monthly Metering Process - Performance Rating Section 4: Metering Service Provider - Business Process Review

Audit Objective (Per RFP)	Audit Procedures Performed	*Section Reference*
Adequacy and conformance to good utility practice of preventive maintenance performed on metering equipment, including completeness of maintenance programs, test results and sealing records.	We physically visited the six MTD central sites and reviewed the following documents, records and reports to check compliance with WESM Manual and other applicable rules: - Preventive Maintenance (PM) policies and procedures; and - Preventive Maintenance (PM) records for meters and instrument transformers. Moreover, we performed individual inspection of the PM records (for revenue meters and instrument transformers) of the in-scope substations visited to check compliance with the applicable PM schedules, including completeness of the maintenance programs, test results and sealing records.	Section 5: Metering Installation - Central Site Inspection and Physical Site Inspection
Availability and reliability of the meter communication links and interfaces to the meter data collection system of MSP	We performed IT General Controls review focusing on the reliability and security of the data collection capabilities of the communication links and the different software application programs being used in the metering process. The ITGC review covered the following major areas related to the software programs for the metering process: 1. Entity Level Controls 2. Access Controls 3. Program Changes / Development 4. Computer Operations Likewise, we understood the VEE process and identified, analyzed and assessed the adequacy of the software and programs used in meter data collection and validation. Also, we performed physical inspection on the availability and reliability of the communication links and interfaces of the metering sites subjected for the review.	Section 3: Market Operator - IT General Controls Review; and Validation Estimation and Editing Process Review and Data Accuracy Testing; Section 4: Metering Service Provider - Business Process Review; and IT General Controls Review; and Section 5: Metering Installation - Physical Site Inspection
Security of meter data during transmission and receipt between the MO and MSP		
Adequacy of the software and programs used by the MSP in meter data collection, metering database and data validation		
Adequacy of the process used by the Market Operator (MO) in estimation and editing of meter data	We identified and understood the VEE process through interviews and walkthrough with BSMD personnel. We also reviewed the scope of the validation and estimation procedures including the different tools and worksheets used, and incorporated the results of the specific areas covered by the ITGC review to come up with a more valuable set of recommendations.	Section 3: Market Operator - Validation, Estimation and Editing Process Review and Data Accuracy Testing; and IT General Controls Review

Audit Objective (Per RFP)	Audit Procedures Performed	*Section Reference*
Adequacy of remote monitoring facilities to alert the MO of any failure of any component of the metering installation	We interviewed key personnel and conducted walkthrough on the MTR process and other related procedures on how failures in the metering installations are detected and corrected. Also, we incorporated the results of the ITGC review for computer operations to check on the adequacy of system logs that record exceptions like failed validation procedures and communication errors between metering points and the system, user activities, and information security events.	Section 4: Metering Service Provider - Business Process Review; and IT General Controls Review
Adequacy of physical security provided to the metering equipment	We physically visited the different in-scope substations to check the existing security measures provided to the metering installations and related equipments. We also assessed the effectivity of and compliance to these security measures.	Section 5: Metering Installation - Physical Site Inspection
Adequacy of physical and logical access security provided to metering data held in metering installations and to the corresponding database	We also visited the data center of both the MO and MSP to observe physical security controls in place. To cover logical access, we performed IT General Controls review focusing on user access controls and segregation of duties.	Section 3: Market Operator - IT General Controls Review Section 4: Metering Service Provider - IT General Controls Review
Availability of recovery plan and procedures in case of erased or corrupted metering data and of an offsite data storage location	We interviewed key personnel from the MO and MSP regarding their backup data storage and restoration procedures. We also performed ITGC review on the adequacy of disaster recovery or business continuity plans in place to prevent or reduce the risk of loss of information and services.	Section 4: Metering Service Provider - IT General Controls Review - Computer Operations - Disaster Recovery / Business Continuity
Accuracy of metering installation based on test results	We performed actual on-site testing and verification of the meter's performance using widely accepted procedures and use of ERC-certified meter testing devices and equipments.	Section 5: Metering Installation - Meter Integrity Testing
Availability of spare parts in case of defective metering installations that needs immediate replacement	We conducted interview and walkthrough on the procurement and inventory monitoring process being performed by the NGCP Head Office for metering equipments and spare parts. We also viewed the online Materials Management System (MMS) to confirm its functionalities related to inventory monitoring.	Section 5: Metering Installation - Central Site Inspection - Inventory Monitoring

Audit Objective (Per RFP)	Audit Procedures Performed	*Section Reference*
Availability of check meters for WESM main meters	We physically visited the different in-scope substations to check on the availability of check (back-up or alternate) meters in place, understood the WESM Manual and other relevant standards on the applicability and importance of the check meters on the entire metering process and provided recommendations based on the audit procedures performed.	Section 5: Metering Installation - Physical Site Inspection - Alternate Meters
Appropriateness of the revenue metering and market trading node location (MTN)	We interviewed key personnel from BSMD to understand the current situation of the revenue metering and MTNs. From there, we assessed the information gathered against better practices in other electricity markets.	Section 3: Market Operator - Appropriateness of Revenue Metering and Market Trading Node Location
Accuracy of the results of the Site Specific Loss Adjustments (SSLA) calculations	We understood the SSLA process and relevant formula used, and reperformed various SSLA calculations made by BSMD on sample billing periods.	Section 3: Market Operator - Site-Specific Loss Adjustment Process Review and Data Accuracy Testing

Appendix 15: Mapping of Observations and Audit Requirements

Table 26: Mapping of Observations and Audit Requirements

	Observations	Ref. No.	Page Ref.	Audit Req. Ref.
Critical Non - Compliances		None		
Major Non - Compliances				
1	Meter Seals Provision	MI – PI12	43	ix
2	Perimeter Security	MI – PI17, MI – PI18, MI – PI19 & MI – PI20	44	ix
Incidental Non - Compliance				
1	Adjusted Loads Vs. Site Specific Loss Factors	PEMC – SSLA02	47	xvii
2	Functional Display	MI – PI03	49	ii
3	Cabinet Housing	MI – PI05	51	ix
5	Enclosure Security	MI - PI08	53	ix
5	Meter Time vs. System	MI – PI04	55	ii
Non – Compliances to Documented Internal Business Procedures				
1	Work Instruction Manual	PEMC – ITGC01	58	v
2	User Access Management	PEMC – ITGC02	59	x
3	Use of User ID	PEMC – ITGC03	62	x
4	Formal User Access Review Process	PEMC – ITGC04	64	x
Observations Requiring Immediate Corrective Action				
1	Manual Business Process Implemented in BSMD	PEMC – VEE01	65	v
2	Manual Elements in the Issuance of the Monthly Metering Validation Report	PEMC – VEE08	67	iv
3	Reconciled Site Specific Loss Adjustment (SSLA) vs. SSLA Models	PEMC – SSLA01	68	xvii
4	Unusually Large Line Losses in SSLA Data	PEMC – SSLA03	70	xvii
5	Large negative losses in SSLA data (MF3MITOBENE08)	PEMC – SSLA04	71	xvii
6	Large Line Losses in SSLA Data (MF3MROSCEPZ03)	PEMC – SSLA05	73	xvii
7	Market Network Model	PEMC – MTNL01	74	xvi
8	User Password Management	PEMC – ITGC05	75	x
9	Metering Installation Registration Form (MIRF) Record Keeping and Maintenance	MI – PI01	77	iv
10	Meter Seals Inventory and Log	MI – PI11	79	ix
11	Grounding Resistance on Instrument Transformers	MI – PI16	81	ix
12	Structure of Instrument Transformers	MI – PI15	82	ii

	Observations	Ref. No.	Page Ref.	Audit Req. Ref.
Other Observations				
1	Calculations in Monthly Meter Trouble Reports	PEMC – VEE07	84	iv
2	Meter Data Transferred via CD	NGCP – BPR01	85	
3	Environment to Test the System Changes in MSP	NGCP – ITGC05	85	iv
4	Disaster Recovery / Business Continuity Plan in MSP	NGCP – ITGC06	86	xi
5	Testing of Backup Data in MSP	NGCP – ITGC08	87	
6	Communication Link	MI – PI02	87	iii
7	Alternate Meters	MI – PI09	89	xv
8	Accuracy of TOPD's RTU Averaging	PEMC – VEE02	90	iv
9	PEMC's Internal Procedures on Checking the Accuracy of RTU averaging	PEMC – VEE03	91	iv
10	RTU Data Quality Flags	PEMC – VEE04	91	v
11	Visual Comparison of the Load	PEMC – VEE05	92	v
12	Automation of Manual Comparison of Data	PEMC – VEE06	93	iv
13	Procedural Manual in MSP	NGCP – BPR02	94	vii
14	Formal Information Security Responsibilities for MV90 in MSP	NGCP – ITGC01	94	vii
15	User and System Administration Policies for MV90 in MSP	NGCP – ITGC02	95	x
16	Password Configuration Settings for MV90 in MSP	NGCP – ITGC03	96	x
17	Formal Change Management Policies and Procedures in MSP	NGCP – ITGC04	97	iv
18	Audit Logs for User Activities in MSP	NGCP – ITGC07	98	iv
19	Anti – Virus Software in MSP	NGCP – ITGC09	99	xi
20	Ventilation	MI – PI06	100	ix
Opportunities for Improvements				
1	Site Specific Loss Adjustment Process	OFI1	101	xvi
2	Irregularities in Some Generated Daily SSLA Results	OFI2	101	xvi
3	SSLA Template File Maintenance	OFI3	102	xvi
4	Determination of Switching Configuration	OFI4	103	xvi
5	Handling of Missing Data in Monthly SSLA Results	OFI5	103	xvi
6	Spurious Loss Adjustments	OFI6	104	ix
7	Policies and Procedures Regarding Information Security in MSP	OFI7	105	ix
8	Internal Review of the Operating Effectiveness of the Information Security Policies and Procedures in MSP	OFI8	106	ix
9	Policies and Procedures Regarding Remote Access Security in MSP	OFI9	106	ix

	Observations	Ref. No.	Page Ref.	Audit Req. Ref.
10	Segregation of Duties in MSP	OFI10	107	ix
11	Review of Program Access Security in MSP	OFI11	107	ix
12	Password Management in MSP	OFI12	108	ix
13	Policies and Procedures regarding Physical Access Security in MSP	OFI3	109	ix
14	Capacity Planning in MSP	OFI14	109	ix
15	Incident Management in MSP	OFI15	110	x
16	Cryptographic Controls in MSP	OFI16	111	ix
17	Preventive Maintenance Policies for the Metering Installation	OFI17	111	ii
18	Test Switch	MI – PI10	114	ii
19	Instrument Transformer Type and Construction	MI – PI13 & MI – PI14	115	ix
20	Viewing Window	MI – PI07	116	ix

Appendix 16: Metering Site Visit Pictures

North Luzon North

Observations on Grounding Connection

Northwind – Low compression, single hole

INECO – Non-standard Ground Connection (spliced; poor contact)

Observations on Perimeter

CAGELCO – Heavy vegetation

Good Point Observations

CAGELCO – Conduit connection is sealed

Bakun HEP – Grounding has 2-hole long barreled connector

CAGELCO – Pull-box with seal

CAGELCO – Secondary terminal box modified to accommodate seals

Observations on Grounding Connection

AFAB – Poor grounding connection

Masinloc – Overhead ground interconnection

PELCO II Guagua – Manner of connection

Observations on Grounding Connection (Continued)

PELCO II Guagua – Ordinary U-bolt used

PUD – Non-standard connection

Observations on Perimeter

AFAB – Excessive vegetation growth

PUD – With vegetation growth (grass was cleaned only hours before inspection)

Non-functional Meter Display

Masinloc – Blackened meter display

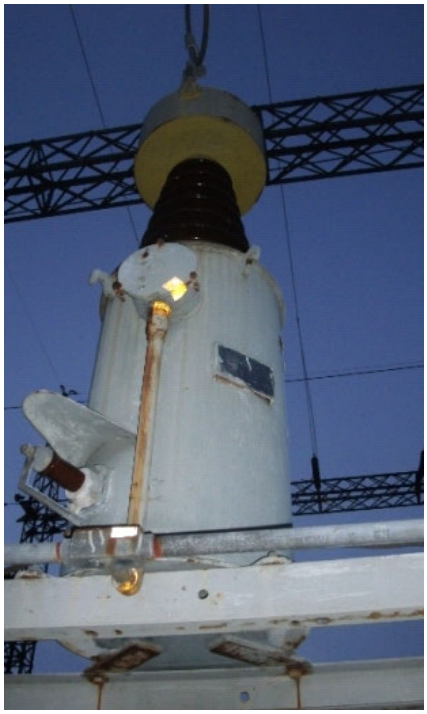
SBMA – Blackened meter display

Use of Sticker Seals Only

AFAB – Sticker seal on secondary terminal box

Bataan CCPP – Sticker seal used

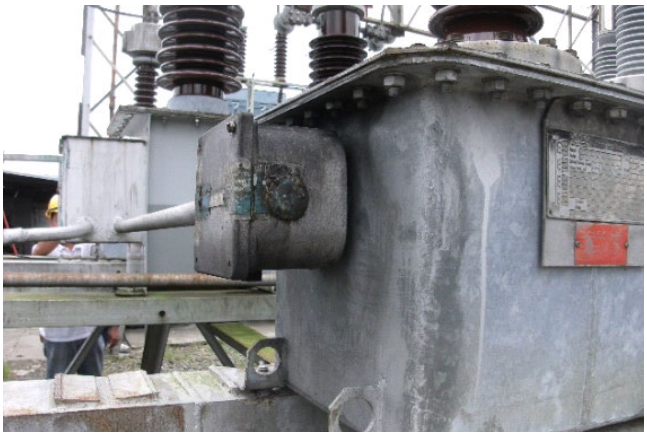
Corrosion and Oil Leaks



AFAB – Corroded conduit

PUD – Meter enclosure is heavily corroded

PELCO II Guagua – Corroded tank and structure



PELCO II Guagua – Oil leak

PELCO II Guagua – Low height of structures

Good Point Observations

Hanjin – (1) With grounding window for common ground tapping; (2) with space heater to maintain humidity

Good Point Observations (Continued)

PELCO II Guagua – Mechanical and sticker seals combined

Petron – Joints of all conduits are sealed

Observations on Grounding Connection

Biñan – (1) Frayed conductor; and (2) melted conductor

Biñan – (1) Non-standard connection; and (2) poor connection

Observations on Grounding Connection (Continued)

Makban – Corroded ground with poor connector

Use of Seals

CBK – No seal; only cable tie was used

Zapote – Secondary terminal box has no seal

Non-functional Meter Display

Angeles Electric – Blackened meter display

Rosario – Blackened meter display

Observations on Perimeter

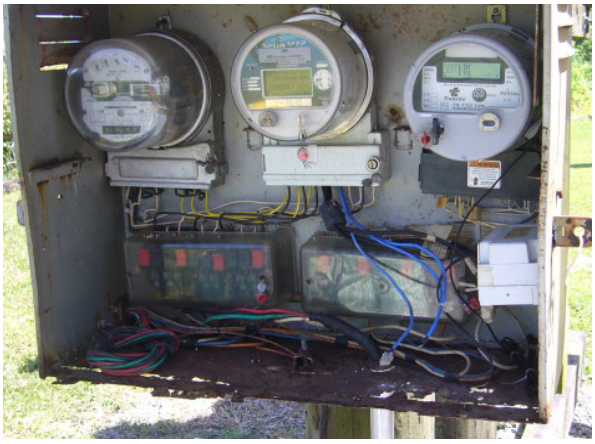
Clark Electric Distribution Corp – Heavy vegetation

Republic Cement Norzagaray – Heavy vegetation

Northern Cement – No perimeter protection (fence or gate)

Meter Enclosure

UPLB – Dilapidated meter enclosure



Meralco TMC2 – Heavily corroded meter enclosure

Presence of Unwanted Materials/Objects

Biñan – Second terminal box with bird's nest

Untagged Meter

Makban – Untagged meter

CBK – Untagged panel mounted meters

Contaminated Bushings

Northern Cement Corp. – Heavily contaminated bushings of CT and PT

Observations on Facility Structures

Philex Mining – Rusted facility structures

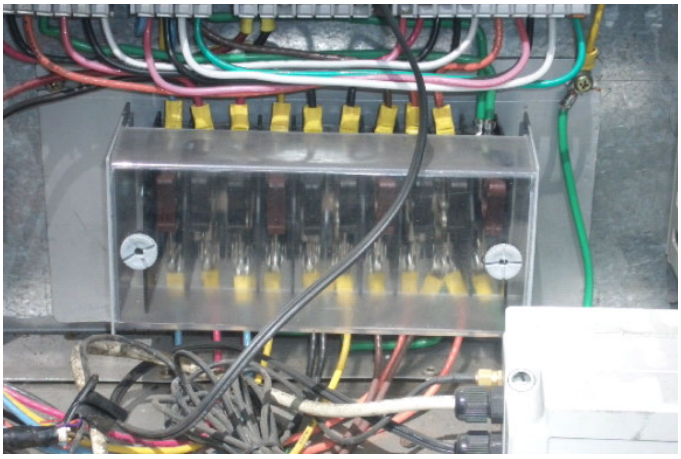
HEDCOR – Rotted Pole Structure

Observations on Grounding Connections

Cebu Thermal – (1) All ground conductors tapped at a single point (structure ground); and (2) ground connection using ordinary solderless connector

Carmen Copper - Ground connection by splicing (instead of exothermic or compression method)

Use of Seals



Toledo – Test block has no seals

KEPCO – Secondary terminal box has no provision for seals

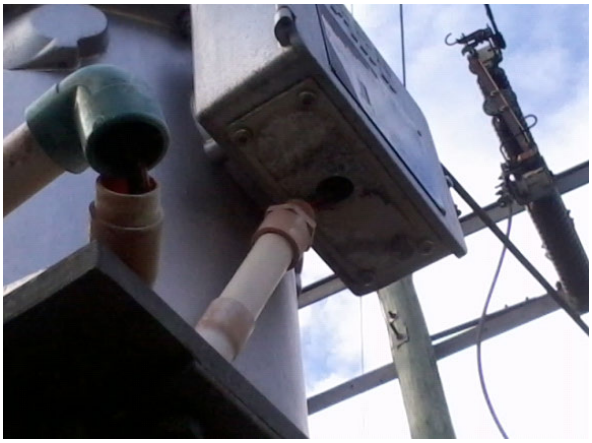
Oil Leaks

MEPZA 1 – (1) PT Phase B has oil leak; and (2) oil deposit at surface caused by Phase B oil leak

Contaminated Bushings

DORECO – CT/PT have contaminated bushings

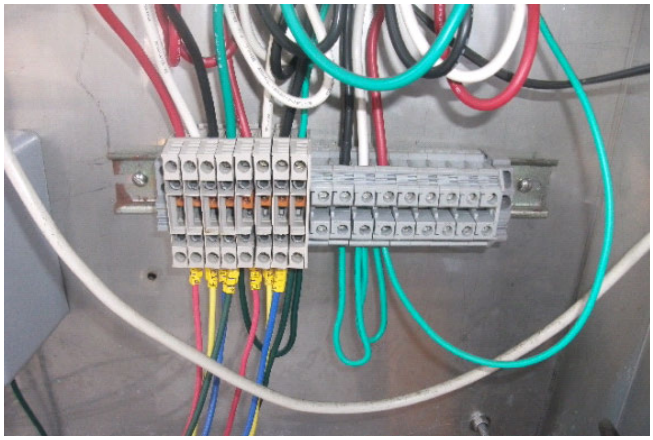
Maintenance of Structures



NORECO II – Loose conduit

TOLEDO – PT (hole at conservator 2)

Observations on Test Block



Cebu Thermal – Ordinary terminal block used

TOLEDO – Ordinary terminal block used

Good Point Observation

KEPCO – Ground down conductor
(jacketed, green, big loop, with protection at grade level)

Observations on Grounding Connections

AKELCO Altavas – Single grounding

Observations on Perimeter

AKELCO – Heavy vegetation with debris

Observations on Perimeter (Continued)


CAPELCO Sigma – (1) Broken perimeter gate; and (2) presence of excessive vegetation

Presence of Unwanted Materials/Objects


CENECO Alijis – Presence of dead snake on secondary terminal box

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