# Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)

## Marshalls Energy Company, Inc. – Majuro, Marshall Islands

Ordered by the Pacific Power Association (PPA)
Prepared by KEMA Inc

December 23, 2010 – Final Report

Experience you can trust.

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# 1. Executive Summary

KEMA's analysis of the Marshall Energy Company, Inc. (ME C) power system determined total losses of 26.88% consisting of:

- 8.45% in power station auxiliaries (station losses), which is a relatively high amount of losses. Typically, station losses are lower than 5%.
- 0.67% in street lighting (which should be accoun ted for and billed. If these revenues cannot be collected, street lighting should be considered a financial loss for MEC and not a system loss).
- 6.41% in technical losses.
- 11.35% in non-technical losses.

Technical and non-technical losses total 17.76%.

**Recommendations:**

*Section 9 and the Appendices contain detailed cost and benefit information.*

**A. Generation**

1. Operate generating units at high efficiency. The engines should be properly maintained and operated near 80% of full rated output. Funding of on-going maintenance requirements is not included.
2. Develop a generator dispatching routine to provide highest efficiency operation.
3. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.
4. Train power plant operators on load forecasting and economic dispatch practices. Include an economic dispatch module in future SCADA system plans.

(Total cost of these initiatives is estimated to be $1.3 million over 6 years.)

## B. Distribution

1. Develop standard specifications for distribution and power transformer purchases, which are based on reducing lifetime costs (the costs of capital, losses and maintenance). For example, the cost of 1 kW of core losses for 10 years at 20 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $13,270 (NPV). For copper losses the NPV is dependent on the transformer loading but is estimated to be $8,000. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in "Technical Loss Calculation and Financial Model" tab spreadsheet in Appendix C).

2. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to specific distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious need due to excessive tampering, by-passing or where total transformer loads are necessary. For transformer load profiling 50 to 100 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.

3. Optimize distribution transformer ratings over a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).

4. Use an infrared camera to scan power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.

(Total cost of these initiatives is estimated to be $1.4 million over 6 years.)

## C. Metering, Billing and Collection

1. Staff a Revenue Protection Department or empower a Revenue Assurance Officer to form a group responsible for reducing non-technical losses, who will execute a revenue assurance program that includes regular and un-announced program audits.

2. Replace customer meters with digital smart meters (pre-paid).

(Total cost of these initiatives is estimated to be $3.7 million over 6 years.)

Recommended measures and actions will cost $6.4 million over a 4-to-6 year period, resulting in an estimated savings of $9.2 million (NPV of $ 1.3 million) and reduction of:

- 2% for station losses (auxiliaries).
- 2% for technical losses.
- 5% to 6% for non-technical losses. Continuous attention in this effort can further lead to even additional improvements of 4% to 5% of energy savings.
- Savings of $150,000 per year can be achieved for every 1% improvement in generation efficiency.

Note that MEC is already in the process of replacing all the street lights with LED lights which will save them an additional $514,000 over 6 years. 20% of the remaining consumption in LED lights should be allocated and billed to proper users and not considered an energy loss. Furthermore attention must be paid to faulty photocells which keep the lights on during daytime.

# 2. Introduction

## 2.1 Project Objectives

KEMA was asked by the Pacific Power Association (PPA) to conduct an energy efficiency study titled: "Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)" for the 10 Northern Pacific Island Utilities. This report summarizes study results for Marshalls Energy Company Inc. in Majuro, Marshall Islands.

Project objectives:

- Quantify energy losses in the power system.
- Prepare an Electrical Data Handbook containing electrical characteristics for all high voltage equipment.
- Prepare digital circuit model of the power system EASY POWER, an established commercial package.
- Prepare a prioritized replacement list of power system equipment to reduce technical losses.
- Identify sources of non-technical losses.

## 2.2 Quantification of Losses

Losses are due to:

- Power station losses.
- Losses in the transmission system.
- Losses in the distribution system.
- All three categories of losses are quantified.

The following loss categories were identified.

- Station Losses: Power Plant Auxiliary Loads.
- Transmission & Distribution System Losses:
  - Technical losses: Summation of transformer core losses, transformer copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. Technical losses will be higher as power factors drop below unity.
  - Non-technical losses: Inaccurate meters, meter tampering or by-passing, theft, meter reading errors, irregularities with pre-paid meters, administrative failures, and wrong multiplying factors.
- Unbilled Usages: Energy consumption that is not billed should be considered a financial loss rather than a non-technical loss. The unbilled usage is mostly for stre et lighting.

# 3. Data Gathering and Assessment of Current Situation

Data gathering process is to collect existing information and understand the current situation of the generation, transmission, and distribution systems. KEMA visited Majuro and conducted meetings with management and staff. Physical inspection was selectively done of two power plants and electrical distribution facilities, including transformer stations, mid-line breakers, distribution transformers, and overhead feeders.

## 3.1 The MEC Power System

Marshalls Energy Corporation owns and operates two power plants, all diesel engines and 13.8 kV generators in parallel configuration to provide residential, commercial, and governmental customers through three 13.8 kV feeders composite of overhead line and underground cable. Furthermore, MEC owns and operates generation on the islands of Jaluit, Wotje, Rongrong, Kili Island and Bikini atolls.

Power is distributed at 240/120 V, 208/120 V or 480/277 V levels through distribution transformers with kVA capacities ranging from 25 kVA to 750 kVA. System peak load is 10.5 MW with an average load level below 30 percent of the connected capacity.

## 3.2 KEMA Data Request

Before KEMA visited Majuro, a data request was sent to MEC. For the data request documents see Appendix A.

## 3.3 Data Received

KEMA did not receive any data before the visit.

## 3.4 Site Visit

Additional data was gathered during the site visit of February, 2010.

**Load:**

Load has been decreasing over the years. The current peak is 10.5 MW with an average of 8.5 MW. Some large industrial/commercial users, like a fish processing plant, shut down. Another fish processing plant and the fish processing company installed its own power generation. Until generator engines are repaired, additional load cannot be served. A copper mill runs about two months per year (but used to run much longer) with a power demand of 1MW. A large portion of the residential lighting load has been switched to high efficiency, compact fluorescent lights (CFL).

**Exhibit 3-1: Average Hourly Load of All Engines**

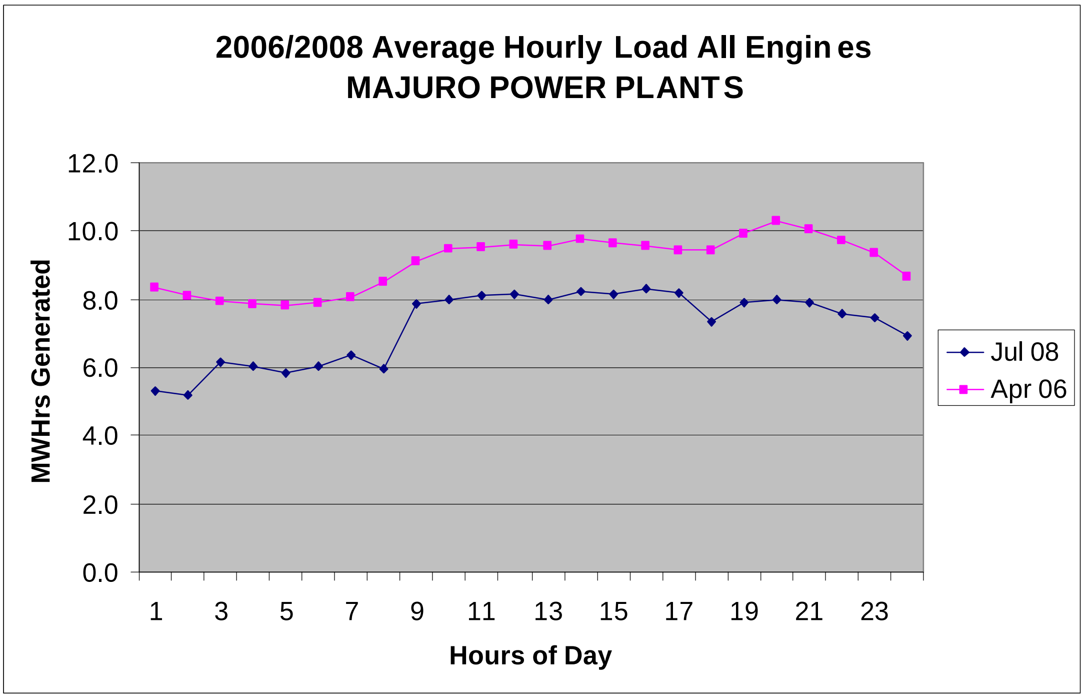


**Exhibit 3-2: Feeder F1**

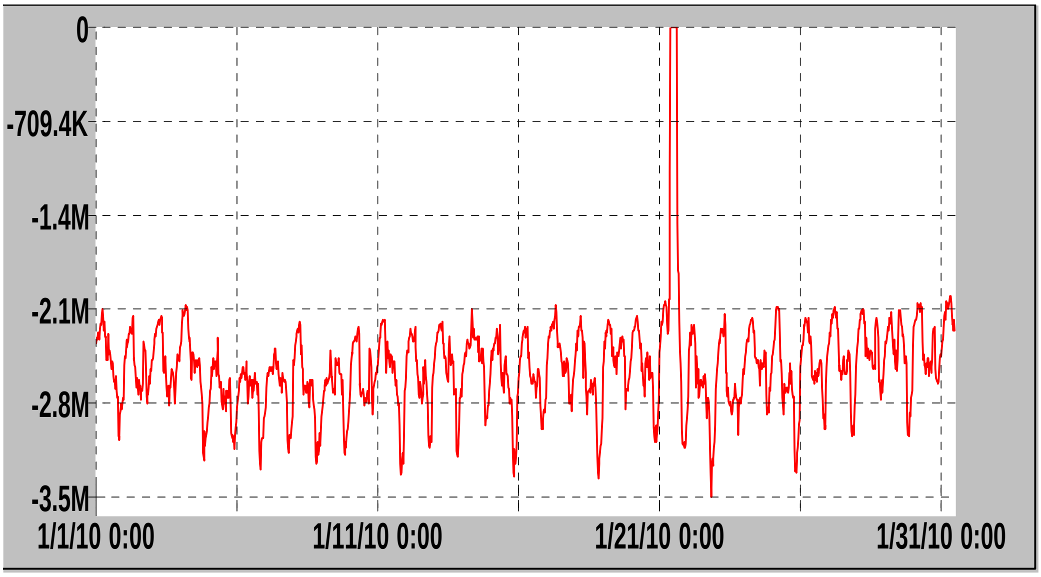



**Exhibit 3-3: Feeder F2**

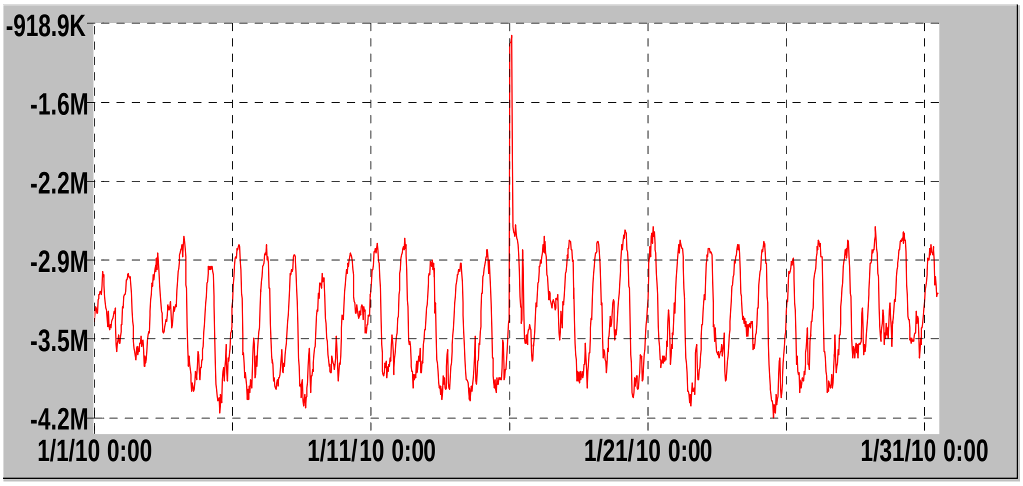
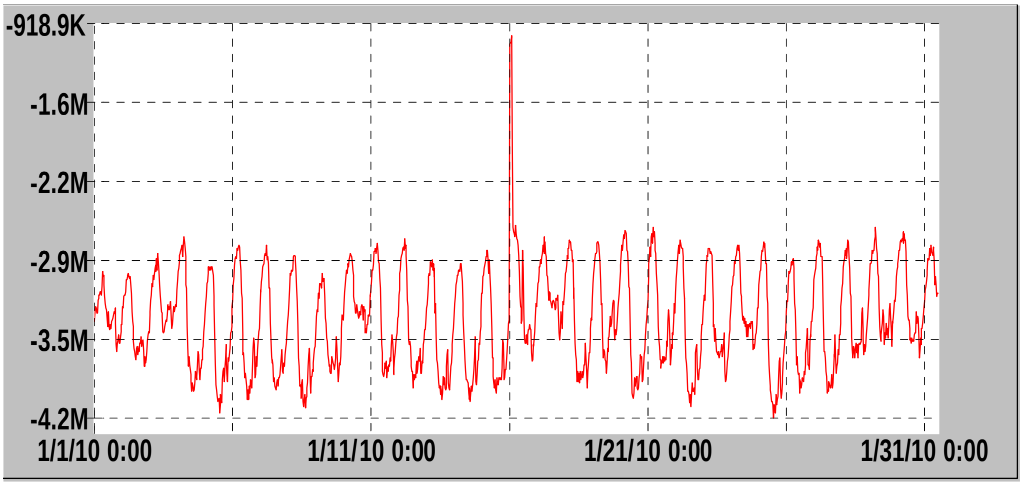


**Exhibit 3-4: Feeder F3**




**Reliability:**

Each feeder has planned outages 8 hours per month. Unplanned outages range from 2 to 3 hours per month per customer. Tree faults cause many of the unplanned outages.

Maintenance: Maintenance is performed but on an affordable schedule and scale, not necessarily when needed.

**Conductors:**

Aerial cables are 2/O for 13.8 and 4.16 kV circuits. Underground cables have similar sizes.

**Transformers:**

Distribution transformer sizes are 25 kVA and above.

Selected name plate ratings from a 19-Feb-2010 inspection trip:

Howard: 750 kVA, 13.8 kV / 208Y/20 V, 5.8%

Copper: 75 kVA, 4.9%

T&R Electrical Supply: 226 kVA, 13.8 kV /208Y / 120 V, 3.3%

T&R: 25kVA, 1.9%, 4160 to 240/120 V, 1.9%

T&R: 112.5kVA, 4160 V 208Y/120 V, 1.9%

T&R: 50kVA, 13.8 kV, 240 / 120 V, 2.7%

**Generating Units:** (running inspection trip)

#2 was producing 2.2 MW, 1MVAr, 0.9pf, 105A

#1 was producing 1.5MW, 0.9 MVAr, 0.87pf, 70A

#7 was producing 4.8MW (limit), 1.6 MVAr, 0.92 pf, 210A

Station #2 auxiliaries were using 400 A at 480 V

All 13.8 kV vacuum circuit breakers (generator breakers) have a short circuit current breaking capacity of 25 kA.

**Other Information:**

There are 675 street lights, averaging 175 W each, many of which do not turn off during the day. None of the streetlights are owned by the utility. All were funded by the local government, community groups and donors and installed by the utility when power was cheap. 270 out of 675 are on private property. Nobody wants to pay for the power used and MEC has been told by the government not to remove the lights.

Eight amplifiers for the cable TV system are unmetered.

On average, five customers per month are caught tampering. It could be 3 to 5 times higher. The fine for tampering is $500 plus payment for the estimated energy use since the last meter reading.

Meter multipliers are being checked by the distribution engineer.

Split bolts are used to repair aerial conductors. There are many of these kinds of repairs. Bad contacts and resulting heat/energy loss is a potential issue.

**Capital Improvements :**

MEC is scheduled to receive $1 million from the Asian Development Bank to replace pole top transformers and conductors.

Other data collected is given in the Electrical Data Handbook – See Appendix B.

# 4. Grid Model and Calculation of Technical Losses

## 4.1 Estimates and Assumptions for Missing Data

To quantify losses, the following assumptions were made:

1. The averaged power output over the past 3 years was used for annual energy consumption.
2. A typical value for power transformer no load and full load losses literature [1] was used for the core losses.
3. Secondary service wire types and sizes were provided. Assumptions were made for average wire lengths and general structures.
4. Loads were distributed along the feeders based on feeder sections and assumed meter locations along the feeders from meter reader books.
5. The allocation of distribution transformers and loads were according to feeder sections shown on the GIS map.
6. Load was allocated proportionally to the kVA capacities of the distribution transformers.
7. Estimated voltage drops through feeders were not considered in the loss estimations. Actual voltage drops were calculated in the EASY POWER system model.

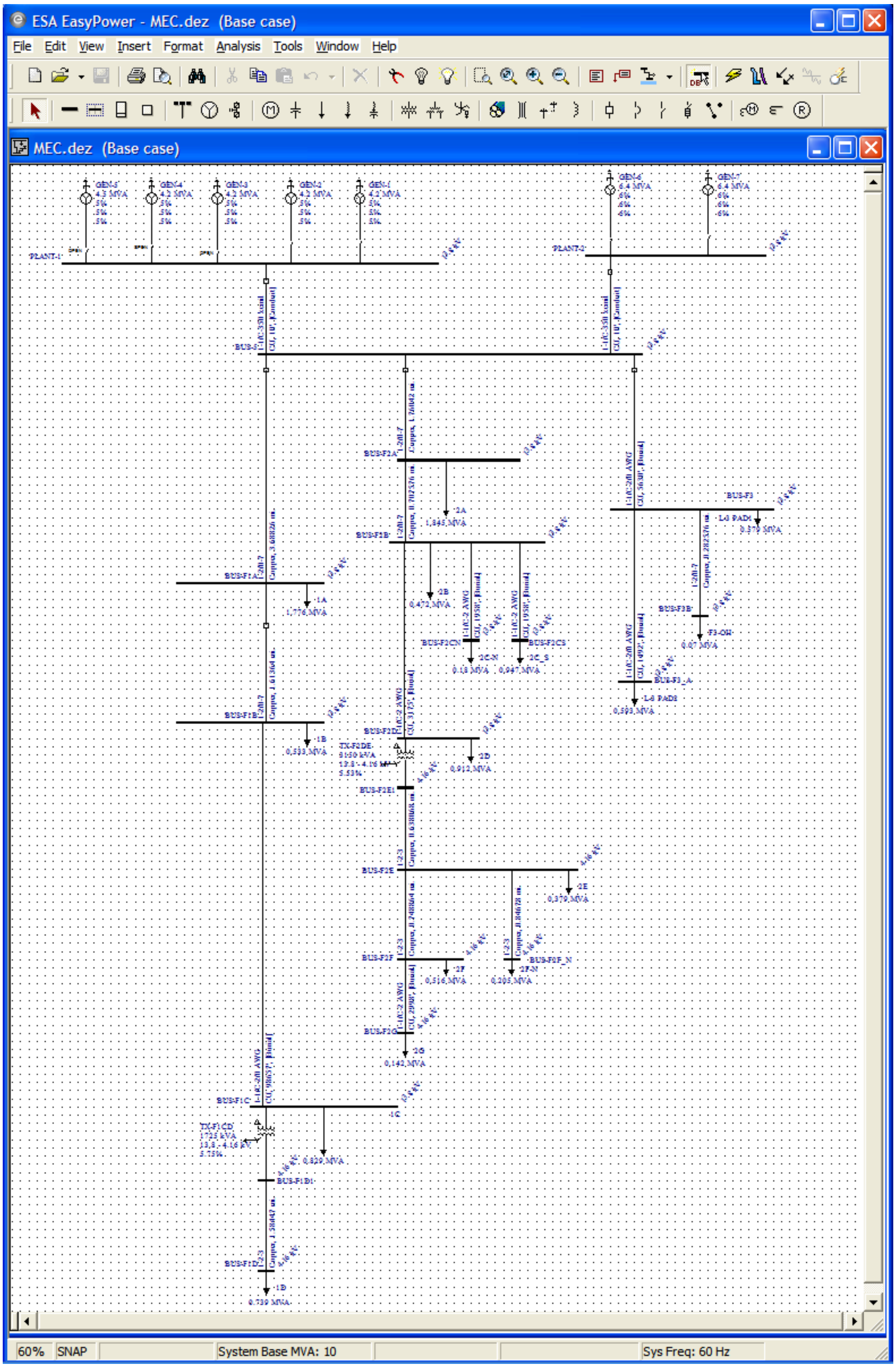
## 4.2 Easy Power Model

Power plants and primary feeders of the distribution system in Majuro Island were modeled in Easy Power. Losses through primary feeders and power transformers were calculated in a power flow study. Peak loads were estimated from the 12 month customer meter data and generator output data collected from the two power plants. Since distribution transformers are not associated with customer meters, load allocation was based on transformer sizes for each of the three feeders.

The system one-line diagram is shown in Exhibit 4-1.

[1] Electric Power Distribution System Engineering, by Turan Gonen

## Exhibit 4-1: MEC One line diagram



## 4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

**Technical losses:** The sum of transmission line losses, primary feeders, power transformers, distribution transformers, and secondary wires. Except for transmission lines, primary feeders and power transformer copper losses, all other losses were calculated in Excel sheets. Where information was not sufficient, assumptions (exact location of customers relative to their distribution transformer, load for each of the transformers, load on feeders, load per phase of feeder sections, power factor of the loads) were made to facilitate the estimation.

**Non-technical losses:** The difference between total system losses and technical losses; e.g., the total energy entering the system from the power plants minus total energy sold.

For MEC, the unbilled energy usage came from street lights, TV amplifiers and water system usage. Street light power usage has even been higher because of faulty photocells.

## Exhibit 4-2: Loss Calculations

| MEC Preliminary Loss Calculations | | | |
|---|---|---|---|
| | **Avg. MWh for 2006 to 2008** | **% based on Energy Generated** | **% based on Energy delivered to the Distribution System** |
| Generator Output | 75747 | 100.00% | |
| Generated Output – Auxiliaries | 69346 | 91.55% | 100.00% |
| Energy sold to customers | 55381 | 73.11% | 79.86% |
| Technical Losses (including feeders, transformers and service wires) | 4858 | 6.41% | 7.01% |
| Secondary Service Losses | 144 | 0.19% | 0.21% |
| Distribution Wire losses | 3145 | 4.15% | 4.54% |
| Distribution Transformer Copper Losses | 168 | 0.22% | 0.24% |
| Transformer Core Losses | 1277 | 1.69% | 1.84% |
| Power Transformer Losses (13.8 to 4.16 kV) | 126 | 0.17% | 0.18% |
| Street Lights | 510 | 0.67% | 0.74% |
| Non-Technical Loss | 8598 | 11.35% | 12.40% |
| Station Auxiliaries | 6401 | 8.45% | |

# 5. Electrical Data Handbook

As part of the project's scope of work, KEMA prepared an Electrical Data Handbook, containing electrical characteristics of MEC's high voltage power system equipment.

The Handbook can be found in Appendix B.

# 6. Analysis of Technical and Non-Technical Losses

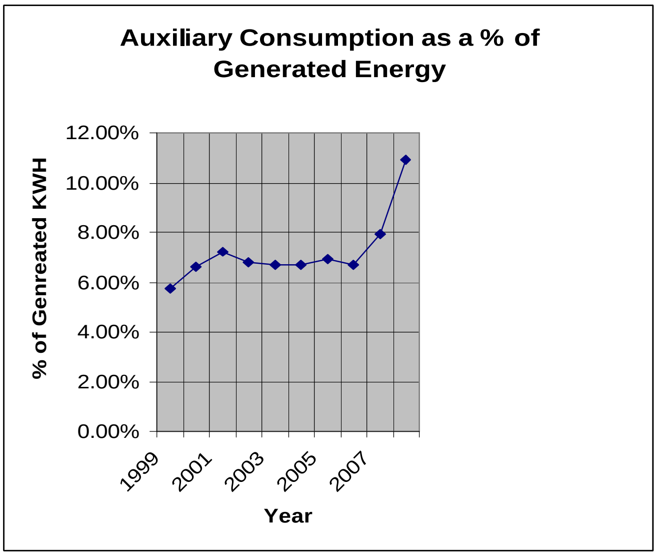
## 6.1 Generation Efficiency

Overall generation efficiency has been improving from 2004 to 2008 (14.12 to 15.18 kWh / Gallon). Prior to 2004, the efficiency of the combined operation was erratic. Individual machine data was available. Similar efficiency improvements were experienced in lube oil use (1664 kWh / gallon in 2004 and 3083 kWh / gallon in 2008) .

### 6.1.1 Power Plant Usage, Station Losses

The power plants are consuming 8.45% of the generated energy . Auxiliary consumption has increased substantially in the last two years (7% to 11%).

**Exhibit 6-1: Auxiliary Consumption**




Auxiliary consumption measurement is not performed with revenue-class meters, which makes it difficult to verify these values. Auxiliary load consists of sea water pumps for engine cooling and building supply and exhaust fans.

Power Station 2 supply fans and exhaust fans run continuously when either one or both engines are running to keep the building pressurized and the corrosive environment out. In Power Station 1, one sea water pump is required for engine cooling but two may be running due to suction restrictions/problems at the pump house. Sea water pump inlet filters are continually blocked with floating and submerged trash, which accumulates with port usage and climatic conditions. This requires regular cleaning of the intake screens and heat exchangers, which requires a shutdown of the cooling system and associated engines.

All fans are controllable through AC frequency drives or manually through Programmable Logic Controllers (PLC) designed to optimize fan control, based on coolant temperatures. These losses can be reduced 30% with better operational control and management.

## 6.2 Technical Losses

### 6.2.1 Distribution Line Losses

Calculated line losses are 4.15% (as part of 6.41% technical losses) in 13.8 kV and 4.16 kV overhead and underground feeders. Only 0.19% came from low voltage service wires. Non-technical losses are 11.35%.

Theoretical calculation of wire losses (ideal) do not take into account connection losses (e.g., split bolt joints in overhead lines), and losses due to unbalanced loads. Line or wire losses occur because of wire resistance, which is inversely proportional to the size of the conductor and depend on the material used for the conductor. The larger the size (diameter) the lesser is the resistance. A same sized wire made of copper will have lower resistance than aluminum. Resistance also increases if terminations and split bolts are not tight. Metering is recommended at critical points so generation and consumption can be analyzed, and loss estimations verified.

Improving power factors can reduce technical losses. This can be accomplished using switchable capacitor banks. Power Factors at the generating stations were 0.9 without capacitors. Adding capacitors can raise the power factor and reduce line losses.

During the power flow study, attention was paid to voltage drops through primary feeders. MEC's distribution system has long feeder sections with noticeable voltage drops. Since there are no shunt capacitors or voltage regulators on the feeders, the only effective way to keep the voltage at the end of a feeder within 10% of nominal is to increase the terminal voltages or adjust transformer taps. For long feeder sections, shunt capacitor banks or voltage regulators at the load centers are recommended to correct the voltage drops locally and avoid the need to increase generator terminal voltages. By doing this, reactive power is reduced from the generator to the load, reducing the current flow, improving the voltage, and better utilizing power equipment (transformers, feeders, etc.).

### 6.2.2 Transformer Losses

Transformer losses are separated in two parts – no-load losses and copper losses. No -load losses are magnetizing losses which are present whenever the transformer is energized, independent of the load. Even an unloaded but energized transformer will have no -load losses. Copper losses are only present when load is present and are proportional to the square of loading relative to full load. For MEC, total losses from distribution transformers are estimated to be 1,445 MWh per year. 1277 MWh are no -load losses (core losses), and 168 MWh are copper losses.

Ratings of these transformers (having an average load of 27%) may be too large for the loads, resulting in higher no-load losses (core losses). The system database did not contain information that matched loads to transformers; so this will be done by physical inspection. MEC is currently halfway through a project developing this database, which will tie to the billing system but other tasks have demanded a higher priority.

Since core losses depend on transformer ratings and since MEC is using only 27% of the total installed capacity, there is room to decrease these losses. The following table shows how transformer ratings can be lowered one or two sizes and by how much losses can be saved. The second option (two sizes lower) will load transformers to about 50% of the maximum load of 10,500 kW.

**Exhibit 6-2: Transformer Size Changes**

| Strategy to lower transformer losses by lowering size (kVA) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Total kVA | Avg kVA | % reduction | MWh losses | Losses Saved in MWh | % Saved | $ saved @ $0.28 / kWh per year |
| Base | 39805 | 88 | | 1445 | | | |
| One Size Lower | 32560 | 73 | 17.05% | 1135 | 310 | 21.29% | $85,960 |
| Two Size Lower | 22103 | 49 | 44.32% | 1042 | 403 | 27.74% | $112,000 |

Total loss reduction from these transformers will not go above 600 MWh (<5% of total losses or 13,600 MWh) even if all transformers are replaced with smaller ratings. Savings from losses are not enough to justify transformer replacement. The best way to save is to install new transformers that more closely match rated loads as additions and/or replacements are required. Accurate load data for each distribution transformer is essential for proper sizing of replacement transformers. Because of the salty environment, MEC should evaluate the costs and benefits of standardizing on stainless steel enclosures vs. conventional steel enclosures.

## 6.3 Non-Technical Losses

Of the total system losses, 11.35 % is non-technical. KEMA identified some potential non-technical loss causes:

- Street lighting is bundled in the losses.
- Some accounts are not accounted through metering and billing.
- Enforcement of disconnection for non payment is lax.
- Identifying energy theft is left to the meter readers who are part of the community and may not be open to bringing situations to management's attention.
- Meters are not tested and not working properly.
- Meters are old and not working properly.
- No regular procedure to check meter multipliers.

- Organizationally, no person is responsible for reducing system losses.
- The billing system does not raise red flags when irregular consumption is detected.

Energy for street lights should not be considered a system loss, but is more suitably classified as a financial loss since MEC knowingly provides for the good of the people. This is a policy issue. There is a project to replace street lights with more efficient LEDs with a potential savings of $80,000 per year. Energy consumed by the LED lights will still be 20% of the existing light demand and will need to be accounted for.

It should furthermore be noted that currently street lights power usage is even higher than necessary due to faulty photocells.

### 6.3.1 Metering Losses

Customer meters are electromechanical. They have not been calibrated or tested for as long as they have been in service. Meters used for generator output and main feeders are not revenue-class meters. Electromechanical meters tend to be slow and may read 0.5 to 1% less energy than actual energy consumed. New pre-paid digital meters are being considered. The maximum demand from each meter should be recorded and calibration checks should be performed on a regular basis.

Processes: Meter reading, billing and collection processes are manual. Bill collection is lax, resulting in excessive account receivables. Adding pre-paid meters will help to reduce the receivables. As consumers better understand how much energy they are using, reductions in energy consumption can be expected. Management and policy enforcement will be key to successful loss reduction.

Metering and billing losses are part of non-technical losses. With proper process implementation, a 50% improvement in a 3-to-5 year period is possible.

Meters must be tied to transformers in the CIS (Customer Information System). Every year analyses should be performed to identify which transformers can be replaced for loss reduction, overloading issues, and general maintenance. It would be beneficial to add meters to the LV side to capture transformer loadings and tampering issues. Current transformers (CT's) can be installed with the meters on the poles.

# 7. Other Issues

**Power Generation**: Most of the engines were beyond the allowable maintenance intervals (major and minor overhaul). During KEMA's visit, due to the loss of one of the Deutz engines, MEC was load-shedding every day. Funding was not available to buy parts and fuel.

**Feeders, Transformers and Loads:** Aerial feeders are failing due to lack of stainless steel hardware and numerous repairs using split bolts (see picture) and may be causing more losses in the feeders (estimated to be 1%).

Transformers used in Majuro are not made from stainless steel, which are needed for salty environments. There is also a practice of buying repaired transformers from a supplier who does not provide test certificates. Transformers are rusty and need to be replaced. Aerial line hardware and transformers should be made from stainless steel. Transformer specifications must have values for core and copper losses defined for evaluation purposes. For example, the cost of 1 kW of core losses for 10 years of transformer life at 20 cents per kWh of fuel cost will be $13,227 (NPV), and for copper losses the NPV can be $8,000. These figures may change the strategy towards buying lower loss transformers against higher capital costs.

# 8. Options for Improvements

## 8.1 Power System Improvements/Modifications

Technical losses are unavoidable. However, reducing them should continue to be an integral part of MEC's overall loss reduction strategy for the following reasons:

- Electricity rates will continue to increase with increasing fuel prices, which will change the cost-basis for evaluating many technical loss reduction related measures/programs.
- Electrical equipment connections that are corroded or loose can cause heating, which results in higher losses, leading to reliability concerns and safety issues.
- Reducing technical losses is controllable per the results of this study.
- Priority should be given to equipment purchases that lead to lower losses.

Many of the projects/programs that reduce technical losses cannot be cost-justified because of the large capital investment required. For these projects/programs, giving loss reduction benefits a proper weight when considering total life costs is key to selecting those that will be most beneficial.

Determining the accurate amount of technical losses is important to a loss-reduction program, for determining best investments and progress. Installing meters on distribution transformers and keeping the digital system model up to date are important improvement measures.

In addition to the above, loss reduction measures could be implemented in the following areas:

**Secondary Circuits and Service Wires**

MEC should consider using GPS data for a targeted feeder program to create an initial GIS map for secondary circuits (including customers and service wires). The map could be refined gradually to reflect the actual secondary circuit and service wires in the field. This would provide a solid basis for future technical loss evaluation.

Such a GIS map has an advantage in that it can use customer consumption data to more accurately estimate secondary circuit losses and service wire losses.

Customer meters need to be associated with the respective transformers servicing the load. This can be done in a CIS system using spreadsheet software to take load from metering data and calculate transformer loading. Properly sizing the transformers will have a significant impact on overall loss reduction; e.g., using smaller sizes.

Loss estimation in this part of the system is much more complicated and is affected by:

- Un-metered loads such as streetlights, illegal connections, etc.
- Unknown lengths of secondary circuits and service wires.
- Load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed or a study is conducted to classify various categories of customers.

Nevertheless, creating such a GIS map will help MEC better estimate losses.

**Regularly Update Loss Cost-Basis**

The loss cost-basis used to estimate lifetime cost of losses should take electricity rates into full account. When rates are increasing at a slow pace, it may be acceptable to use current rates to calculate projected savings over life spans of equipment (e.g. transformers) and projects. When rates are fast increasing, using current rates will greatly under estimate the life-time savings of reduced losses over a 15-20 year period.

As new equipment is installed and old equipment replaced, this task should be accomplished as soon as possible. Results can also be used to help MEC to re-evaluate other large projects priorities.

Once the new cost-basis is established, it should be applied to new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. This will help to bring in immediate results without any additional costs.

A new cost-basis should also be used to re-evaluate projects/programs that could result in Technical Loss reduction to determine/select the most beneficial ones to be carried out first.

**Optimize Distribution Transformers**

The size of distribution transformers should be optimized. When the transformer sizes are reduced two levels (60 to 70% of the sum of kVA's of distribution transformers) from the existing level, close to $210,000 per year in core loss savings can be realized. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

- Develop the load profile for each transformer and keep it updated once a year (a load profile for each distribution transformer implies a meter per distribution transformer will be needed, unless all customer loads connected to this transformer can be computed).

- Develop proper transformer sizes for each location.

- Optimize transformers which can be optimized without capital cost investments, i.e., by moving them to appropriate locations.

- Develop a new transformer purchase plan based on standard sizing while looking at least lifetime costs, which include capital investment and losses. (An example transformer evaluation of "Technical Loss Calculation and Financial Model" spreadsheet is included in Appendix C).

**Optimize Customer Power Factors**

Overall the system power factor is 0.9. The power factor of feeder sections should be checked regularly (at least once a year) and actions taken to keep it above 0.9, preferably 0.95. The best location for corrective measures is the loads, especially at inductor motor terminals. Develop a plan and tariff (or introduce a low power factor penalty) to make sure each larger commercial and government loads are at a power factor of at least 0.9. If less and if the customer does not improve to the required level, MEC should charge a penalty. Metering and billing should be coordinated with tariff and/or low power factor penalties.

**Optimize Feeder Reactive Power Compensation**

Shunt capacitor banks on 13.8 kV lines can be used to minimize reactive power flows in the network to help reduce the losses. When operated for this purpose, the following areas should be considered.

**1. Fixed and manually switched capacitors.**

Compensation can use a mix of fixed and switched capacitors to achieve desired reactive power compensation levels.

The size of fixed capacitors can be determined by minimum reactive power compensation requirements of a feeder. It is not necessary to compensate to 1.0 power factor, but should be as close as possible. From a loss reduction point of view, results will be the same regardless if the power factor is leading or lagging. The actual size selection should also take standard capacitor sizes into account.

The size of switched capacitors can be determined based on the load pattern of a particular feeder and the granularity of the power factor control . If the reactive power load of a feeder changes between two constant levels, then one large switched capacitor may be sufficient . This should be evaluated on a feeder-by-feeder basis. Determining sizes of switched capacitors requires further study and more detailed information.

Capacitors also affect the voltage profile along a feeder. When determining capacitor sizes, in particular for switched capacitor banks, voltages should be verified to ensure voltage limits are not violated.

## 2. Automatically switched using capacitor controls

Automatic switching of capacitor banks can be controlled by a variety of system variables or derivatives of system variables . Common controls are described below.

- Voltage Control: This is the most common type of control used to switch capacitors in or out of the circuit. They are switched in during low voltage conditions and switched off when the system voltage is high. This type of control is normally used where a drop of 3% or more of voltage occurs during full load . This type of control is not suitable in a tightly voltage regulated system where the voltage is held at constant values.

- Current Control: This control is used where the voltage control cannot be exercised . The capacitor current is excluded from the monitored current and this ensures that the capacitor will be brought on line during heavy load conditions .

- Current Compensated Voltage Control : This type of control is sensitive to voltage but is current compensated. The control acts as simple voltage control so long as the current is below a predetermined level. If current goes above the pre-determined level, the capacitors are brought on line by changing the calibration of the voltage elements. Hence, the capacitors remain in circuit so long as the current is above the pre-determined level. If the voltage starts to rise and becomes high enough to offset the calibration, the capacitor will be switched off. This is a sophisticated control and ensures capacitors are on line when they are most needed.

- Kilo VAr Control: This control operates in response to changes in the power flow. It has no significant advantage over current-compensated control and is usually more expensive.

- Time Control: This type of control is used when daily load patterns are predictable. Capacitors are switched in and out based on the time of day. This control is the least expensive; however, a disadvantage is that it cannot accommodate unusual system conditions such as a sudden loss of lines, etc., and will require manual intervention to switch the bank.

Selection of control type should be based on the load profile of a feeder.

**3. Overhead Feeder Repair**

Overhead feeders are being repaired using split-bolt connections, which increases the possibility of hot spot and energy loss at the connection points. The following is recommended:

- Perform infrared scans on each phase and identify split-bolt connections that are excessively hot.

- Correct to minimize split-bolt connections and develop a plan to replace wire sections.

## 8.2 Operational Recommendations

### 8.2.1 Metering

A procedure should be developed to test and calibrate meters before they are installed. Methodologies must be established to test sample meters (based upon statistical sampling) such that their accuracy can be assured during the lifetime of the meters.

Meters to measure the generator output, auxiliary services and feeder output must be of revenue class accuracy.

Methodologies must be developed to measure distribution transformer load profiles either through software which takes into account the customer meters on each of the transformers or through physically measuring the load by installing demand type meters on the secondary side of each of the transformers.

These meters can be installed while using current transformers (CT's) mounted on the pole or on the pad mounted transformers. It is not necessary to install these meters on all distribution transformers. Areas which are experiencing more tampering, or where transformers seem to be over loaded or under loaded, may benefit from these installations. If customers are equipped with new digital meters and can be linked in a database or in the CIS to the distribution transformers, it may not be necessary to install these meters at the distribution transformers.

### 8.2.2 Generation

Develop written operational procedures and plans for economic dispatch and monitoring of the performance of the plants and of individual generation units.

For reviewing the performance of generating units, the current metering in the power plant does not provide good coordinated readings. KEMA recommends that a first step should be to install revenue class meters (energy, fuel and other supplies) to accurately measure the efficiency of each generator and to be able to dispatch them based upon efficiency considering other operating constraints. Focus on efficiency improvement (which requires training and implementation of processes for the operators) and real time display of engine efficiency helps the operators to run the engines in the most optimal way. Minimum display of real time information providing fuel use, lube oil usage, generator kWh production and auxiliary kWh usage should be made available. The objective of all this is to improve generator efficiency and reduce consumption in plant auxiliaries.

### 8.2.3 Strategy for Reduction of Non-Technical Losses

Considering there are 11.35% of non-technical losses, there are potential savings in this category.

One of the main areas in aligning a utilities' operation to Revenue Assurance is to implement a Revenue Assurance Process making use of an advanced Revenue Intelligence system. For conducting most efficient fraud prevention/detection and revenue operations audits with limited resources, an advanced Revenue Intelligence System is very helpful. Such a system can detect potential fraud based on information from multiple sources using advanced detection rules. It will vastly increase the hit rate and support a range of revenue assurance activities. These changes/processes should include:

- Implementation of a formal Revenue Assurance Process including an overall Audit Process.
- Implementation of Revenue Intelligence software to support Revenue Assurance oriented operations.

However, for a small utility, implementation of a Revenue Assurance Department and implementation of Revenue Intelligence software requires a large investment and may have a large organizational impact.

A more pragmatic approach can be developed to locate non-technical losses and increase the effectiveness of revenue-protection operations.

MEC could consider the following:

- Develop a program for checking old meters.
- Train meter readers to identify tampering, by-passing, broken seals, and hook ups.
- Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplying factors, tariff categories applied to customers, functioning of red flags in the case of irregularities) and non-technical loss causes found by meter readers such as meter tampering or by-passing.
- Select targets for inspection, also focusing on commercial customers. When selecting targets for inspection, the potential of the estimated amount of revenue recovery should be a major selection factor. With limited resources, selecting accounts with highest revenue recovery potential and hit rates will be the most efficient use of limited resources.
- Make operations less predictable. MEC's own experience may show that there are sophisticated fraud activities that take advantage of known patterns of Revenue Assurance operations. This should be countered with less predictable operations; e.g., occasional night inspections, computer-generated random daily target lists, and so on. This will help to identify these fraudsters and increase the deterrent effect.
- Prevent repeat fraud activities. Once a fraud is found, measures should be implemented to ensure it will not occur again.

- Prevent and curb internal collusion activities. One important aspect of effective revenue protection operation is to prevent and curb potential internal collusion. Internal collusion seriously undermines the effectiveness of any revenue assurance process. One possible solution is to bring in non-local inspection teams to conduct critical revenue-protection operations, such as large account audits under the direct control of MEC's top management.

- Employ rights tactics for each group of customers. It is a fact that different types of customers have different needs for electricity, different usage patterns, and different payment capabilities. A successful revenue assurance strategy should take this into account to develop corresponding tactics for each group of customers. In general, customers should be grouped based on their usage patterns and payment capabilities. Establishing typical usage patterns and payment capabilities for each group is a very important task of Revenue Assurance. Results should then be used as the basis for employing right tactics for each group of customers.

- Assign a senior staff member to be Revenue Assurance Officer, responsible for Loss Reduction Strategies, and who plans and initiates loss reduction programs, keeps records of progress, and reports to the General Manager.

# 9. Per Item: Investments Needed, Expected Reduction of Losses, Payback Time

Exhibit 9-1 provides a summary of savings and associated costs over a 6-year implementation period.

**Exhibit 9-1: Savings and Cost**

| | 6 Yrs NPV of Savings and Costs | | |
|---|---|---|---|
| NPV @ Cost of Capital | **Savings (NPV)** | **Cost (NPV)** | **Net (NPV)** |
| Auxiliary loss | $1,674,423 | $1,300,000 | $374,423 |
| Non-Technical Loss | $3,923,849 | $2,998,596 | $925,253 |
| Technical Losses | $1,198,599 | $1,173,056 | $25,543 |
| Total = | $6,796,870 | $5,471,651 | $1,325,219 |
| 1% efficiency improvement in generation saves $149,000 per year based on the price of crude oil of $ 75 per barrel. At a price of $ 100 per barrel a 1% efficiency improvement translates to $190,000 per year in savings. This assumption can be influenced by fuel pricing creditworthiness of customers and transportation costs. | | | |

A summary of assumptions and recommendations follow:

- Costs (including fuel costs) are assumed to increase 3% per year.
- Cost of Capital is assumed to be 8%.
- Emphasis was on process improvements for economic dispatch of generators, design, purchasing, metering, billing, collection and operations.
- Technical and non-technical loss improvements will require investments totaling $5 million over 6 years. Losses will be reduced from 17.76% to less than 11% (calculated value 10.15%).
- Generation auxiliary losses have increased from 6% to 8.45%. With proper process improvements, it is possible to provide real-time data on generator operation to operators to control coolers, fans, and AC frequency drives. The efficiency of generator auxiliaries can be reduced to less than 6.5% energy loss (calculated value 6.23%).

- The overall objective is to reduce losses from 26.88% to below 18% (calculated value 17.53%) in 6 years.

## 9.1 Recommendations

Recommendations below are prioritized according to costs and benefits. (See spreadsheet Savings Model tab in Appendix C.)

### 9.1.1 Reduction of Generation Auxiliary Losses

When generating units are operating, they need fans, radiators, pumps and other equipment for auxiliary services. Manual processes to operate these equipments depend on having good procedures, but these procedures need to be designed with a focus on saving energy.

Improvement measures could include:

- Adding displays to show efficiencies of every generating unit to operators (cost $100,000). Develop a process to measure the efficiency of each generator and develop management reporting on generation efficiency.

- Instrumentation should present real-time and accumulated fuel usage per generator, generator output (kW, kVAr, kWh, power factor), auxiliary per usage (kWh) and real-time display of every generating unit's efficiency keeping historical records for analysis and dispatching purposes.

- Develop manual processes to control fan operation (cooling fans, exhaust fans and pumps) to run based on temperature sensing or other parameters to reduce energy consumption.

- Automate manual processes using PLC controls to motor starters ($250,000).

- Apply Frequency Drives ($950,000).

Benefits from these actions are expected to be $2.3 million over 6 years. Savings are produced by reducing auxiliary losses from 6,401 MWh (8.45%) to 4,160 MWh (6.23%) in 6 years – 2% reduction in 6 years. (See spreadsheet Savings Model tab in Appendix C.)

### 9.1.2 Reduction of Non-Technical Losses

Account and highlight monthly financial losses (i.e., street lights and unaccounted energy usage by MEC offices). Develop a regular meter testing program. Add pre-paid digital meters as part of smart metering for customers (3,600). Add meters to the secondary sides of transformers and feeders (500) at key locations for measuring transformer loads as well as auditing customers fed from each transformer.

Procure meter testing equipment and train on use. Make sure each customer is linked to the transformer and its meter (cost $2,700,000) in a software tool that issues tampering and transformer loading can be easily monitored. Install distribution transformer meters on pad mounted transformers or poles using current transformers. It is not necessary to install meters on every distribution transformer. Areas experiencing excessive tampering and where loading profiles are known will be the best locations. This can also be accomplished by CIS applications linking transformers to customer meters. For transformer load profiling, 50-to-100 temporary recording meters could be installed on the transformers and relocated as needed.

Add Revenue Protection measures with high visibility reporting to the CEO and the Revenue Assurance Officer, with a focus on metering and billing policies and goals, audits of meter reading practices, meter reading data processing and billing processes, irregularities detected, metering installations, meter accuracy, meter constants, multiplier factors, and tampering.

After year 1, 25% of non-technical losses will be saved; after year 6, 55%. Non-technical losses will be reduced from 8,596 MWh to 3,870 MWh in 6 years. Savings in 6 years are expected to be $ 5.3 million, resulting in a NPV of $3.9 million.

### 9.1.3 Reduction of Technical Losses

**1. Power Factor Improvement**

The power factor of MEC is reasonable but it needs to be watched and a process should be developed to evaluate it at least once a year.

- Acquire software for power factor analysis. (Cost of software and training $50,000.)
- Determine power factors at largest customers and require them to improve it over 85% or improve it for them and charge it to customers. This may require penalties or tariff changes if improvements are not realized.

- Add capacitors to improve the power factor (Estimated Cost of $200,000 over 6 years.)

- Determine where capacitors can be placed in the feeders for improving the overall power factor close to 95%. Make sure that a monitoring plan is part of this.

**2. Transformer Sizing**

- Distribution transformers are loaded 27% of full capacity. Loss reduction savings can be achieved by optimizing the ratings over a number of years as new transformers are purchased.

- Determine proper sizes and specifications of distribution transformers to better match loads. Determine standard sizes and relocate such that each transformer is 80% loaded at maximum demand.

- Exchange or replace with right size transformers over a 6-year period. Transformer purchases should consider total life time cost. For example, cost of 1 kW of core losses for 10 years of transformer life at 20 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $13,269 (NPV). Copper losses would be $8,000. (See example of transformer evaluation in "Technical Loss Calculation and Financial Model" tab spreadsheet in Appendix C).

- Cost of right sizing transformers is estimated to be $1,000,000.

**3. Reduce Line Losses**

Acquire an infrared camera and train to use. (Cost of equipment and training $100,000.)

Using an infrared camera is a necessary tool for identifying distribution loss issues. An infrared camera will identify hot spots from bad connections and overloading, and as a result, help in detecting weak spots, prioritizing maintenance work and upgrading feeders. There is a potential energy savings by regularly identifying these maintenance issues and taking proactive correction measures.

Implement a line section replacement program on lines having extensive split bolt repairs. Upgrade 4.16 kV feeders to 13.8 kV over the next 4 years. (Estimated cost of $2.3 million is not included in Exhibit 9-1and Exhibit 9-2.)

These recommendations will lead to expected technical loss reductions of 10% after the first year to 40% after 6 years. Technical losses will drop from 4,858 MWh to 2915 MWh in 6 years with an expected savings of $1.7 million, resulting in an NPV of $1.2 million.

### 9.1.4 Improving generator efficiencies

Every 1% efficiency improvement for the engine generators at a fuel price of $3 per gallon (delivered cost) will result in savings of $149,000 per year and $3.3 million (NPV) over 10 years

Use measured data of fuel input to each engine and record generated and energy used in auxiliaries, to economically dispatch units. Include unit availability, efficiency of the units, and planned maintenance. Cost of additional instrumentation, programmable logic controller and AC frequency drives is estimated to be $1.3 million.

## Exhibit 9-2: Financial Model Results

| **Assumptions:** | | | | |
|---|---|---|---|---|
| Inflation | 3% | | | |
| Cost of Capital | 8.00% | | | |
| Cost/KWh | $0.28 | | | |
| **Cost and Savings list** | **Savings (NPV)** | **Cost (NPV)** | **Net (NPV)** | **Cash over 6 years** |
| **Non-Technical Savings:** | | | | |
| Adding feeder and transformer meters and replacing all other meters | | $2,141,781 | | - $2,635,000 |
| Revenue Assurance | | $856,814 | | - $1,109,946 |
| 55% loss reduction over 6 years | $3,923,849 | | $925,253 | |
| **Technical Loss Savings:** | | | | |
| Infrascan camera and training | | $100,000 | | -$100,000 |
| Right Sizing distribution transformers | | $861,153 | | - $1,040,000 |
| Add power factor capacitors, buy EASY POWER software | | $211,903 | | -$250,000 |
| 40% loss reduction over 6 years | $1,198,599 | | $25,543 | |
| **Auxiliary Losses** | | | | |
| Add freq drives and process improvements on fans, pumps. | | $1,300,000 | | - $1,300,000 |
| 35% loss reduction over 6 years | $1,674,423 | | $374,423 | |

### Other Recommendations:

- Develop a maintenance management program and written operational processes to repair and maintain the transmission and distribution systems and provide related linemen training.

- Perform regular oil sampling and testing of all the power transformers.
- Develop a testing program (bench test) for revenue meters. The estimated cost of $200,000 is not included in the non-technical savings plan.
- Phase out the use of refurbished distribution transformers procurement.

# Appendix A: Data Request

Data Request.xls
Data Request.doc
Inception Report.doc

# Appendix B: Electrical Data Handbook

Data Handbook.doc

# Appendix C: Technical Loss Calculations & Financial Model for Options to Decrease Losses

Technical Loss Calculations and Financial Model.xls